SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2002

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 1-3196

CONSOLIDATED NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

Delaware	**54-1966737**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
120 Tredegar Street Richmond, Virginia	**23219**
(Address of principal executive offices)	(Zip Code)

(804) 819-2000
(Registrant's telephone number)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
7 1/4 % Notes due 2004	—
6.0% Debentures due 2010	New York Stock Exchange
6.8% Debentures due 2027	New York Stock Exchange
6 5/8 % Debentures due 2008	New York Stock Exchange
6 7/8 % Debentures due 2026	New York Stock Exchange
7 3/8 % Debentures due 2005	New York Stock Exchange
6 5/8 % Debentures due 2013	New York Stock Exchange
5 3/4 % Debentures due 2003	New York Stock Exchange
7.8% Trust Preferred Securities, $25 Par	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is an accelerated filer. Yes ☐ No ☒

The aggregate market value of the voting stock held by non-affiliates of the registrant as of February 28, 2003, was zero.

As of February 28, 2003, there were issued and outstanding 100 shares of the registrant's common stock, without par value, all of which were held, beneficially and of record, by Dominion Resources, Inc.

THE REGISTRANT MEETS THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION I.(1)(a) AND (b) OF FORM 10-K AND IS FILING THIS FORM 10-K UNDER THE REDUCED DISCLOSURE FORMAT.

Consolidated Natural Gas Company

Part I

Item 1. Business

The Company

Consolidated Natural Gas Company (CNG or the Company) operates in all phases of the natural gas business, explores for and produces oil, and provides a variety of retail energy marketing services. The Company is a wholly-owned subsidiary of Dominion Resources, Inc. (Dominion), a fully integrated gas and electric holding company headquartered in Richmond, Virginia. The Company is a public utility holding company registered under the Public Utility Holding Company Act of 1935 (1935 Act).

On January 28, 2000, Dominion completed the acquisition of CNG and merged CNG into a subsidiary (New Company) of Dominion. The New Company was incorporated in Delaware in 1999 and at the time of the merger changed its name to Consolidated Natural Gas Company. The "Company" is used throughout this report and, depending on the context of its use, refer to CNG, one of CNG's consolidated subsidiaries, or the entirety of CNG and its consolidated subsidiaries, both before and after the merger with Dominion.

At December 31, 2002, the Company had approximately 4,500 employees. Approximately 2,700 employees are subject to collective bargaining agreements.

The Company's principal executive offices are located at 120 Tredegar Street, Richmond, Virginia 23219 and its telephone number is (804) 819-2000.

Operating Segments

The Company manages its operations through three principal operating segments: Delivery, Energy and Exploration & Production.

Energy manages the Company's gas transmission pipeline, certain gas production, storage and by-product operations and energy marketing activities. **Delivery** manages the Company's retail gas distribution system and customer service operations. **Exploration & Production** manages the Company's onshore and offshore gas and oil exploration, development and production operations. They are located in several major producing basins in the lower 48 states, including the outer continental shelf and deep-water areas of the Gulf of Mexico.

The Company also reports the activities of CNG International Corporation and other minor subsidiaries in its Corporate and Other segment. CNG International was involved in, among other activities, the development and operation of a 26-megawatt power plant located on the island of Kauai, Hawaii. In 2000, management committed to a plan of disposal for CNG International. See Note 8 to the Consolidated Financial Statements for more information.

While the Company manages its daily operations as described above, the assets remain wholly-owned by its legal subsidiaries. For additional financial information on operating segments and geographical areas, see Note 25 to the Consolidated Financial Statements.

Seasonality

Gas sales in the Delivery segment typically vary seasonally based on increased demand for gas by residential and commercial customers for heating use based on changes in temperature. The Energy segment is also impacted by seasonal changes in the prices of commodities that it actively markets. For the Exploration & Production segment, gas prices can vary seasonally as well.

Competition

Delivery

Deregulation is at varying stages in the three states in which the Company's gas distribution subsidiaries operate. In Pennsylvania, supplier choice is available for all residential and small commercial customers. In Ohio, legislation has not been enacted to require supplier choice for residential and commercial natural gas consumers. However, the Company offers an Energy Choice program to customers on its own initiative, in cooperation with the Public Utilities Commission of Ohio (Ohio Commission).

West Virginia legislation currently does not require customer choice in its retail natural gas markets and the Company has not voluntarily initiated an Energy Choice program. However, the West Virginia Public Service Commission (West Virginia Commission) recently issued regulations to govern pooling services, one of the tools that natural gas suppliers may utilize to provide retail customer choice in the future. In 2002, the West Virginia Commission proposed rules that require competitive gas service providers be licensed in West Virginia. In addition, the West Virginia Commission is developing rules for a code of conduct between utilities and their marketing affiliates, as well as consumer protection regulations and marketer licensing rules.

See *Regulated Gas Distribution Operations* in *Future Issues and Outlook* in Item 7. Management's Discussion and Analysis of Results of Operations (MD&A) for additional information.

Energy

The Company's large underground natural gas storage network and the location of its pipeline system are a significant link between the country's major gas pipelines and large markets in the Northeast and Mid-Atlantic regions and on the East Coast. The Company's pipelines are part of an interconnected gas transmission system which continues to provide local distribution companies, marketers, power generators, and industrial and commercial customers the accessibility of supplies nationwide.

The Company competes with domestic and Canadian pipeline companies and gas marketers seeking to provide or arrange transportation, storage and other services for customers. Alternative energy sources, such as oil or coal, provide another level of competition. Although competition is based primarily on price, the array of services that can be provided to customers is also an important factor. The combination of capacity rights held on certain longline pipelines, a large storage capability and the availability of numerous receipt and delivery points along its own pipeline system enables the Company to tailor its services to meet the needs of individual customers.

Exploration & Production

The Company conducts exploration and production operations in several major gas and oil producing basins in the lower 48 states, including the outer continental shelf and deep-water areas of the Gulf of Mexico. Competitors range from major international oil companies to smaller, independent producers.

The Company faces significant competition in the bidding for federal offshore leases and in obtaining leases and drilling rights for onshore properties. Since the Company is the operator of a number of properties, it also faces competition in securing drilling equipment and supplies for exploration and development.

In terms of its production activities, the Company sells most of its deliverable natural gas and oil into short and intermediate-term markets. The Company faces challenges related to the marketing of its natural gas and oil production due to the contraction of participants in the energy marketing industry. In the wake of the current industry developments, several energy trading participants have exited the business, reducing the number of active purchasers in the marketplace and reducing the Company's delivery flexibility. However, the Company owns a large and diverse natural gas and oil portfolio and maintains an active gas and oil marketing presence in its primary production regions which strengthens its knowledge of the marketplace and delivery options.

Regulation

General

The Company is subject to regulation by the Securities and Exchange Commission (SEC), the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency (EPA), Department of Energy (DOE), the Army Corps of Engineers and other federal, state and local authorities.

State Regulation

The Company's gas distribution business subsidiaries are subject to regulation of rates and other aspects of their businesses by the states in which they operate—Ohio, Pennsylvania and West Virginia. When necessary the Company's gas distribution subsidiaries seek general rate increases on a timely basis to recover increased operating costs and to ensure that rates of return are compatible with the cost of raising capital. In addition to general rate increases, certain of the Company's gas distribution subsidiaries make routine separate filings with their respective state regulatory commissions to reflect changes in the costs of purchased gas. These purchased gas costs are recovered through a mechanism that ensures dollar for dollar recovery of prudently incurred costs. Costs incurred that are expected to be recovered in future rates are deferred as regulatory assets.

In November 2002, the Company filed comments in response to the Ohio Commission's request for information needed to ensure that Ohio public utilities are not impacted by adverse financial consequences of parent or affiliate company unregulated operations. The Company informed the Ohio Commission that its affiliate and parent company transactions are governed by the rules of the 1935 Act. The Ohio Commission has not acted on the comments filed or given any indication as to how it will proceed at this time.

For additional information on deregulation in the gas industry and current rate matters, see above in *Competition* and *Regulated Gas Distribution Operations* in *Future Issues and Outlook* in MD&A.

Public Utility Holding Company Act of 1935

The Company and Dominion are registered holding companies under the 1935 Act. The 1935 Act and related regulations issued by the SEC govern activities of the Company, Dominion and their subsidiaries with respect to the issuance and acquisition of securities, acquisition and sale of utility assets, certain transactions among affiliates, engaging in business activities not directly related to the utility or energy business, and other matters. Over the past few years, several bills have been introduced in Congress to repeal the 1935 Act, and repeal provisions are currently pending before Congress. The likelihood that such repeal will be enacted is highly uncertain.

Federal Energy Regulatory Commission

FERC regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, as amended. FERC also has jurisdiction over the construction of pipeline and related facilities used in transportation and storage of natural gas in interstate commerce.

The Company's interstate gas transportation and storage activities are regulated under the Natural Gas Act of 1938 and are conducted in accordance with certificates, tariffs and service agreements on file with FERC. The Company is also subject to the Natural Gas Pipeline Safety Act of 1968, which authorizes the establishment and enforcement of federal pipeline safety standards and places jurisdiction of these standards with the Department of Transportation.

Competition in the natural gas industry was increased by FERC Order 636, issued in 1992. FERC Order 636 requires transmission pipelines to operate as open-access transporters and provide transportation and storage services on an equal basis for all gas supplies, whether purchased from the Company or from another gas supplier.

In the spring of 2003, FERC expects to issue new rules governing standards of conduct between interstate electric transmission and gas transportation and storage providers and its energy related affiliates. One goal of FERC is to eliminate the separate standards of conduct regulations for natural gas pipelines and electric transmission utilities and replace these requirements with uniform standards applicable to interstate "Transmission Providers" of both natural gas and electricity. For additional discussion on FERC matters, see *Interstate Gas Transmission Operations—FERC Policy Developments* in *Future Issues and Outlook* in MD&A.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws and regulations govern both current and future operations and potentially extend to plant sites formerly owned or operated by its subsidiaries, or their predecessors.

The Company is subject to the Federal Clean Air Act and the Federal Clean Air Act Amendments of 1990 (collectively referred to as the Clean Air Act), which require Title V permits for major facilities. The Clean Air Act also requires installation of Maximum Available Control Technology (MACT) to control the emissions of certain hazardous air pollutants from compressor engines. The Company is evaluating MACT proposed regulations but has not yet estimated the cost of expenditures that may ultimately be required.

The states within the Company's operating area are currently developing regulations to reduce nitrogen oxide (NO_x) emissions to reach NO_x budget targets established by the EPA in order to meet goals under the Clean Air Act Amendments of 1990. Estimates of future cost impacts range from $15 to $18 million.

The EPA amended its oil pollution prevention regulations in July 2002. The total projected cost of compliance with the new regulations is estimated to range from $11 to $25 million, representing primarily capital expenditures.

For discussion of significant aspects of these matters, see *Environmental Matters* in *Future Issues and Outlook* in MD&A, Item 3. Legal Proceedings, and Note 21 to the Consolidated Financial Statements.

Gas Supply

The Company's gas supply is obtained from various sources, including: purchases from major and independent producers in the Southwest and Midwest regions; purchases from local producers in the Appalachian area; purchases from gas marketers; and withdrawals from the Company's and third-party underground storage fields.

The Company continues to purchase volumes from the array of accessible producing basins using its firm capacity resources. These purchased supplies include Appalachian resources in Ohio, Pennsylvania and West Virginia, and production from the Gulf Coast, Mid-Continent and offshore areas. Upon FERC's restructuring of the interstate pipeline business in 1992 and 1993, pipelines no longer sell the delivered natural gas commodity; rather, customers provide their own gas supply for wholesale storage and/or delivery by the pipelines. Much of the supply is purchased by local distributors, energy marketing companies or end-users, under seasonal or spot purchase agreements.

Gas Storage

The Company's underground storage facilities play an important part in balancing gas supply with sales demand and are essential to servicing the the Mid-Atlantic and Northeast's large volume of space-heating business. In addition, storage capacity is an important element in the effective management of both gas supply and pipeline transport capacity. The Company operates 26 underground gas storage fields located in Ohio, Pennsylvania, West Virginia and New York. The Company owns 20 of these storage fields and has joint-ownership with other companies in six of the fields. The total designed capacity of the storage fields, including native gas, is approximately 960 bcf. The Company's share of the total capacity is about 717 bcf. About one-half of the total capacity is base gas which remains in the reservoirs at all times to provide the primary pressure which enables the balance of the gas to be withdrawn as needed.

Dominion Transmission, Inc. (Dominion Transmission) operates 756 bcf of the total designed storage capacity and owns 514 bcf of the Company's capacity. Dominion Transmission utilizes a large portion of its turnable capacity to provide approximately 242 bcf of gas storage service for others. This service is provided principally to local distributors, end-users and other customers serving the Northeast.

The East Ohio Gas Company (Dominion East Ohio) and The Peoples Natural Gas Company (Dominion Peoples) own and operate the remaining 203 bcf of storage capacity. In addition to owning their own storage, these companies, as well as several of the Company's other subsidiaries, have access to a portion of the storage capacity operated by Dominion Transmission. The distribution subsidiaries also have capacity available in storage fields owned by others. The Company controls other acreage in the Appalachian area suitable for the development of additional storage facilities which would enable further expansion of capacity to meet possible future storage needs.

Gas Production

The Company owns 4.5 trillion cubic feet equivalent of proved natural gas reserves and produced almost 800 million cubic feet of natural gas per day and 23 thousand barrels of oil per day in 2002.

The Company utilized production handling and firm transportation contracts to support delivery of our gas and oil in certain market areas. Additional information can also be found in Note 21 to the Consolidated Financial Statements.

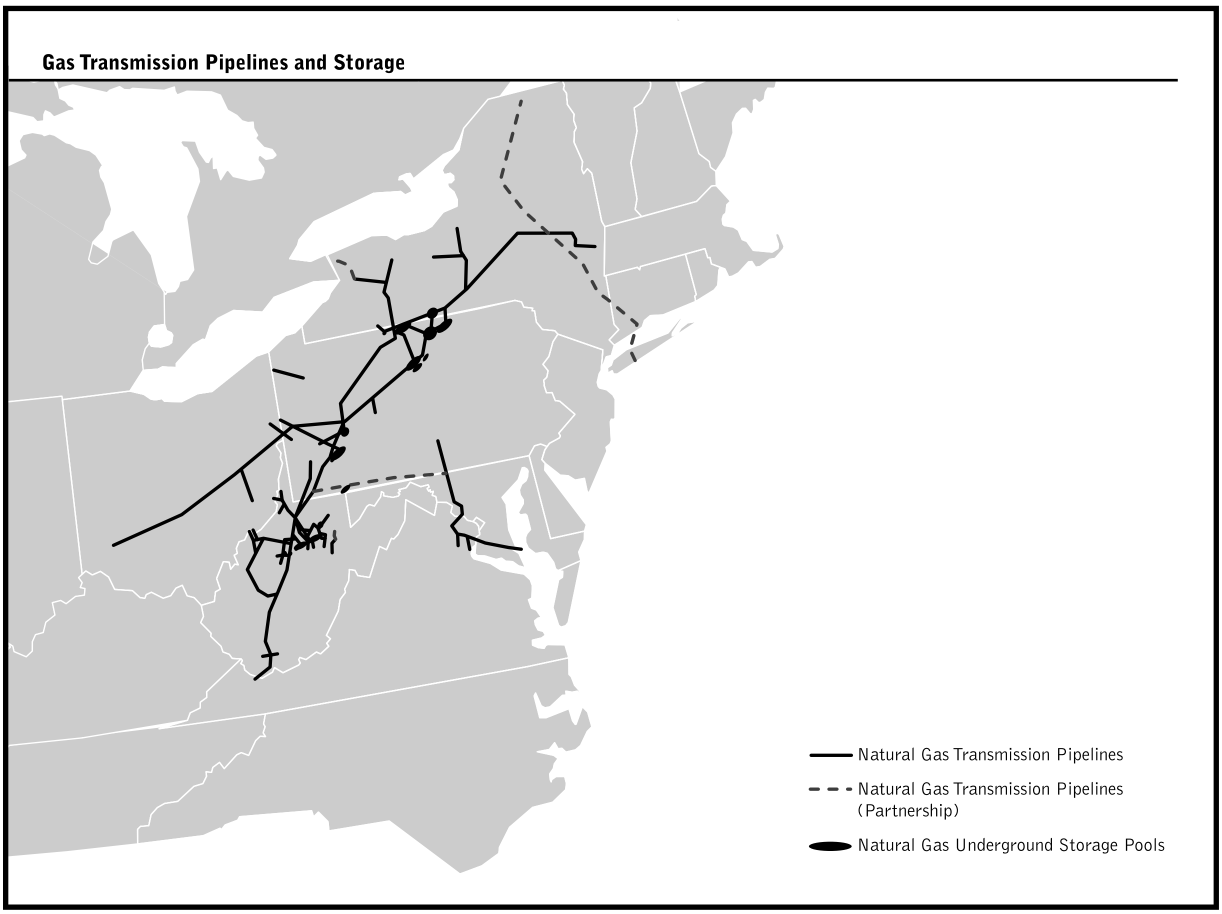
Item 2. Properties

The Company shares its principal executive office in Richmond, Virginia, with its parent company, Dominion. Such office space is leased. The Company leases corporate offices in other cities in which its subsidiaries operate.

Energy and Delivery assets are located primarily in the states of Ohio, West Virginia and Pennsylvania, while Exploration & Production assets include proved reserves located in the Gulf of Mexico, Permian Basin, Mid-Continent Region, the Gulf coast, and the Appalachian area.

The Energy segment's storage operations include 26 storage fields, approximately 373,000 acres of operated leaseholds and 2,000 storage wells. The Energy segment has approximately 7,900 miles of gas transmission, gathering and storage pipelines. The Company also has more than 100 compressor stations with approximately 577,000 installed compressor horsepower located in Ohio, West Virginia, Pennsylvania and New York. See map below for the Company's gas transmission pipelines and storage facilities.

The Delivery segment's investment in its gas distribution network is located in the states of Ohio, Pennsylvania and West Virginia and includes approximately 27,000 miles of pipe, exclusive of service pipe.



Information detailing the Company's gas and oil operations presented on the following pages includes the activity from the Exploration & Production segment and certain production activity in the Energy segment.

Consolidated Natural Gas Company Proved Gas and Oil Reserves

Company-Owned Proved Gas and Oil Reserves

Estimated net quantities of proved gas and oil reserves at December 31 of each of the last three years were as follows:

	2002		2001		2000	
	Proved Developed	Total Proved	Proved Developed	Total Proved	Proved Developed	Total Proved
Proved gas reserves (bcf)						
United States	2,869	3,662	2,347	2,796	973	1,223
Canada	—	—	—	—	1	1
Total proved gas reserves	2,869	3,662	2,347	2,796	974	1,224
Proved oil reserves (000 Bbls)						
United States	47,290	138,328	46,138	115,653	21,328	50,691
Canada	—	—	—	—	6,582	6,582
Total proved oil reserves	47,290	138,328	46,138	115,653	27,910	57,273
Total proved gas and oil reserves (bcfe)	3,153	4,492	2,614	3,490	1,141	1,568

Certain subsidiaries of the Company file Form EIA-23 with the DOE, which reports gross proved reserves, including the working interests share of other owners, for properties operated by such Company subsidiaries. The proved reserves reported in the table above represent the Company's share of proved reserves for all properties, based on the Company's ownership interest in each property. For properties operated by the Company, the difference between the proved reserves reported on Form EIA-23 and the Company-owned proved reserves, reported in the table above, does not exceed five percent. Estimated proved reserves as of December 31, 2002 are based upon studies for each of the Company's property prepared by the Company's staff engineers and reviewed by either Ralph E. Davis Associates, Inc. or Ryder Scott Company, L.P.

Calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC guidelines.

Quantities of Gas and Oil Produced

Quantities of gas and oil produced* during each of the last three years ended December 31 follows:

	2002	2001	2000
Gas production (bcf)			
United States	286	176	173
Oil production (000 bbls)			
United States	8,537	5,989	6,861
Canada	—	—	352
Total oil production	8,537	5,989	7,213
Total gas and oil production (bcfe)	337	212	216

* Gas and oil production quantities include the production from the Exploration & Production segment and certain production activity in the Energy segment.

The average sales price per thousand cubic feet (mcf) of gas (including transfers to other Dominion operations at market prices) realized during the years 2002, 2001 and 2000 was $3.60, $4.03 and $3.12, respectively. The respective average prices without hedging results per mcf of gas produced during the years 2002, 2001 and 2000 were $3.25, $4.14 and $3.90. The respective average prices realized for oil with hedging results were $23.73, $24.58 and $22.96 per barrel and the average prices without hedging results were $25.03, $24.71 and $24.65 per barrel. The average production (lifting) cost per mcf equivalent of gas and oil produced (as calculated per SEC guidelines) during the years 2002, 2001 and 2000 was $0.51, $0.49 and $0.43, respectively.

Net Wells Drilled in the Calendar Year

The number of net wells completed during each of the last three years ended December 31 follows:

	2002	2001	2000
Exploratory:			
United States			
Productive	12	18	2
Dry	12	14	9
Total exploratory	24	32	11
Development:			
United States			
Productive	665	239	125
Dry	38	1	2
Total United States	703	240	127
Canada			
Productive	—	—	9
Dry	—	—	—
Total Canada	—	—	9
Total development	703	240	136
Total wells drilled	727	272	147

As of December 31, 2002, 63 gross (47 net) wells were in process of drilling, including wells temporarily suspended.

Acreage

The following table sets forth the gross and net developed and undeveloped acreage of the Company at December 31, 2002:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Acreage	3,228,492	2,106,858	2,332,472	1,325,687

Productive Wells

The number of productive gas and oil wells in which Dominion's subsidiaries had an interest at December 31, 2002, follow:

	Gross	Net
Total gas wells	19,335	12,156
Total oil wells	278	206

The number of productive wells includes 196 gross (73 net) multiple completion gas wells and 10 gross (4 net) multiple completion oil wells.

Item 3. Legal Proceedings

From time to time, the Company and its subsidiaries are alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans, or permits issued by various federal, state and local agencies for the construction or operation of facilities. From time to time, there may be administrative proceedings on these matters pending. In addition, in the normal course of business, Dominion and its subsidiaries are involved in various legal proceedings. Management believes that the ultimate resolution of these proceedings will not have a material adverse effect on the Company's financial position, liquidity or results of operations.

See *Regulation* under Item 1. Business, *Rate Matters* in *Future Issues and Outlook* in MD&A and Note 21 to the Consolidated Financial Statements for additional information on rate matters and various regulatory proceedings to which the Company is a party.

Before being acquired by Dominion, Louis Dreyfus Natural Gas Corp. (Louis Dreyfus) and two predecessor companies were named as a defendant in several lawsuits originally filed in 1995 that were subsequently consolidated. The lawsuit is now pending in the Texas 93rd Judicial District Court in Hildago County, Texas. The lawsuit alleges that gas wells and related pipeline facilities operated by Louis Dreyfus, and other facilities operated by other defendants, caused an underground hydrocarbon plume in McAllen, Texas. The plaintiffs claim that they have suffered damages, including property damage and lost profits as a result of the plume and seek compensation for these items.

In July 1997, Jack Grynberg, an oil and gas entrepreneur, brought suit against CNG and several of its subsidiaries. The suit seeks damages for alleged fraudulent mismeasurement of gas volumes and underreporting of gas royalties from gas production taken from federal leases. In 2002, the valuation portion of the claim was dismissed. The plaintiff has filed an appeal.

In April 1998, Harrold E. (Gene) Wright, an oil and gas entrepreneur, brought suit against CNG Producing Company, a subsidiary of CNG, alleging various fraudulent valuation practices in the payment of royalties on federal leases. Shortly after filing, this case was consolidated under the Federal Multidistrict Litigation rules with the Grynberg case noted above. A substantial portion of the claim against CNG Producing Company was resolved by settlement in late 2002; however, the suit remains consolidated with the Grynberg case.

In 1999, a class action was filed by Quinque Operating Co. and others parties against approximately 300 defendants, including CNG and several of its subsidiaries, in Stevens County, Kansas. The complaint seeks damages for alleged fraud, misrepresentation, conversion and assorted other claims, in the measurement and payment of gas royalties from privately held gas leases. The plaintiffs will seek class certification and expedited discovery in Kansas. The defendants have filed motions to dismiss the case. A motion in opposition to class certification was argued in January 2003.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Part II

Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters

Dominion Resources, Inc. (Dominion) owns all of the Company's common stock.

The Company paid quarterly cash dividends on its common stock to Dominion during 2002 and 2001 as follows. Restrictions on the payment of dividends by the Company are discussed in Note 19 to the Consolidated Financial Statements.

	Quarter			
	First	Second	Third	Fourth
	(Millions)			
Dividends Paid:				
2002	$151	$ 55	$55	$123
2001	$ —	$178	$56	$102

Item 6. Selected Financial Data

Omitted pursuant to General Instruction I.(2)(a).

Item 7. Management's Discussion and Analysis of Results of Operations

Introduction

Management's Discussion and Analysis of Results of Operations (MD&A) discusses the results of operations and general financial condition of Consolidated Natural Gas Company. MD&A should be read in conjunction with the Consolidated Financial Statements. The "Company" is used throughout MD&A and, depending on the context of its use, may represent any of the following: the legal entity, Consolidated Natural Gas Company, one of Consolidated Natural Gas Company's consolidated subsidiaries or the entirety of Consolidated Natural Gas Company and its consolidated subsidiaries. The Company is a wholly-owned subsidiary of Dominion.

Risk Factors and Cautionary Statements That May Affect Future Results

This report contains statements concerning the Company's expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. In most cases, the reader can identify these forward-looking statements by words such as "anticipate," "estimate," "forecast," "expect," "believe," "should," "could," "plan," "may" or other similar words.

The Company makes forward-looking statements with full knowledge that risks and uncertainties exist that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ are often presented with the forward-looking statements themselves. In addition, other factors could cause actual results to differ materially from those indicated in any forward-looking statement. These factors include weather conditions; fluctuations in energy-related commodities prices and the effect these could have on the Company's earnings, liquidity position and the underlying value of its assets; counterparty credit risk; capital market conditions, including equity price risk due to marketable equity securities held as investments in trusts and benefit plans; fluctuations in interest rates; changes in rating agency requirements or ratings; changes in accounting standards; the risks of operating businesses in regulated industries that are becoming deregulated; completing the divestiture of CNG International Corporation (CNG International); collective bargaining agreements and labor negotiations; and political and economic conditions (including inflation rates). Some more specific risks are discussed below.

The Company bases its forward-looking statements on management's beliefs and assumptions using information available at the time the statements are made. The Company cautions the reader not to place undue reliance on its forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, materially differ from actual results. The Company undertakes no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

The Company's operations are weather sensitive—The Company's results of operations can be affected by changes in the weather. Weather conditions directly influence the demand for natural gas and affect the price of energy commodities. In addition, severe weather, including hurricanes, can be destructive, disrupting operations and causing production delays and unusual maintenance or repairs.

The Company is subject to complex government regulation that could adversely affect its operations—The Company's operations are subject to extensive regulation and require numerous permits, approvals and certificates from federal, state and local governmental agencies. The Company must also comply with environmental legislation and other regulations. Management believes the necessary approvals have been obtained for the Company's existing operations and that its business is conducted in accordance with applicable laws. However, new laws or regulations, or the revision or reinterpretation of existing laws or regulations, may require the Company to incur additional expenses.

Costs of environmental compliance, liabilities and litigation could exceed the Company's estimates—Compliance with federal, state and local environmental laws and regulations may result in increased capital, operating and other costs, including remediation and containment and monitoring obligations. In addition, the Company may be a responsible party for environmental clean up at a site identified by a regulatory body. Management cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean up costs and compliance, and the possibility that changes will be made to the current environmental laws and regulations. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties.

The use of derivative instruments could result in financial losses—The Company uses derivative instruments, including futures, forwards, options and swaps, to manage its commodity and financial market risks. In the future, the Company could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts. For additional information concerning derivatives, see *Market Rate Sensitive Instruments and Risk Management* in MD&A and Notes 2 and 11 to the Consolidated Financial Statements.

The Company's exploration and production business is dependent on factors including commodity prices which cannot be predicted or controlled—The Company's exploration and production business is subject to numerous risks beyond its control. These factors include fluctuations in natural gas and crude oil prices, results of future drilling and well completion activities, the Company's ability to acquire additional land positions in competitive lease areas, and operational risks that are inherent in the exploration and production business and could result in the disruption of production. In addition, in connection with the use of financial derivatives to hedge future sales of gas and oil production, the Company's liquidity may sometimes be affected by margin requirements. Under these requirements, the Company must deposit funds with counterparties to cover the fair value of covered contracts in excess of agreed-upon credit limits. Some of these factors could have compounding effects that could also affect the Company's financial results. Also, because the Company follows the full cost method of accounting for gas and oil exploration and production activities prescribed by the Securities and Exchange Commission (SEC), short-term market declines in the prices of natural gas and oil could adversely affect its financial results. Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized. The principal limitation is that these capitalized amounts may not exceed the present value of estimated future net revenue based on hedge-adjusted period-end prices from the production of proved gas and oil reserves (the ceiling test). If net capitalized costs exceed the ceiling test, at the end of any quarterly period, then a permanent write-down of the assets must be recognized in that period.

An inability to access financial markets could affect the execution of the Company's business plan—The Company relies on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flows from its operations. Management believes that the Company will maintain sufficient access to these financial markets based upon current credit ratings. However, certain disruptions outside of the Company's control may increase its cost of borrowing or restrict its ability to access one or more financial markets. Such disruptions could include an economic downturn, the bankruptcy of an unrelated energy company or changes to the Company's credit ratings. Restrictions on the Company's ability to access financial markets may affect its ability to execute its business plan as scheduled.

Changing rating agency requirements could negatively affect the Company's growth and business strategy—As of March 1, 2003, the Company's senior unsecured debt is rated BBB+, stable outlook, by Standard & Poor's

Ratings Group, a division of The McGraw-Hill Companies, Inc. (Standard & Poor's), and Baa1, negative outlook, by Moody's Investors Service (Moody's). Both agencies have recently implemented more stringent applications of the financial requirements for various ratings levels. In order to maintain its current credit ratings in light of these or future new requirements, the Company may find it necessary to take steps or change its business plans in ways that may adversely affect its growth and earnings. A reduction in the Company's credit ratings by either Standard & Poor's or Moody's could increase its borrowing costs and adversely affect operating results.

Potential changes in accounting practices may adversely affect the Company's financial results—The Company cannot predict the impact of future changes in accounting regulations or practices in general with respect to public companies, the energy industry or on its operations specifically. New accounting standards could be issued by the Financial Accounting Standards Board (FASB) or the SEC that could change the way the Company records revenue, expenses, assets and liabilities. These changes in accounting standards could adversely affect the Company's reported earnings or increases in liabilities.

Operating Segments

In general, management's discussion of the Company's results of operations focuses on the contributions of its operating segments. The Company is organized primarily on the basis of products and services sold in the United States. The Company manages its operations based on the three primary operating segments: Delivery, Energy and Exploration & Production.

Delivery manages the Company's retail gas distribution systems, as well as customer service. The operating results of the Delivery segment reflect the impact of weather on demand for natural gas and customer growth as influenced by overall economic conditions. The Delivery businesses are subject to cost-of-service rate regulation; changes in prices of commodities consumed or delivered are generally recoverable in rates charged to customers. However, certain rates may be subject to price caps, limiting recovery of higher costs in certain circumstances.

Energy manages the Company's gas transmission pipeline, certain gas production, storage and by-product operations and energy marketing activities. The operating results of the Energy segment also reflect the impact of weather on demand for natural gas, customer growth as influenced by overall economic conditions and changes in prices of commodities. The Energy segment's gas transmission operations are subject to cost-of-service rate regulation.

Exploration & Production manages the Company's onshore and offshore gas and oil exploration, development and production operations. Operations are located in several major producing basins in the lower 48 states, including the outer continental shelf and deep-water areas of the Gulf of Mexico. The operating results of the Exploration & Production segment reflect the successful discovery of and production from natural gas and oil reserves, as well as changes in prices of natural gas and oil. Exploration & Production manages commodity risk through the use of derivative contracts such as forwards, swaps and options.

In addition, the Company also reports the corporate functions as a segment.

For more information on the Company's segments, see Note 25 to the Consolidated Financial Statements.

Critical Accounting Policies

The Company has identified the following accounting policies that, as a result of the judgments, uncertainties, uniqueness and complexities of the underlying accounting standards and operations involved, could result in material changes to its financial condition or results of operations under different conditions or using different assumptions.

Accounting for risk management contracts at fair value—The Company uses derivative instruments to manage its commodity and financial market risks. The accounting requirements for derivatives and hedging activities are complex; interpretation of these requirements by standard-setting bodies is ongoing. All derivatives, other than specific exceptions, are reported on the Consolidated Balance Sheets at fair value, beginning in 2001. Changes in fair value, except those related to derivative instruments designated as cash flow hedges, are generally included in the determination of the Company's net income at each financial reporting date until the contracts are ultimately settled. The measurement of fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, measurement involves judgment and estimates. These estimates are based on valuation methodologies deemed appropriate by management. For individual contracts, the use of different assumptions could have a material effect on the contract's estimated fair value. In addition, for hedges of forecasted transactions, the Company must estimate the expected future cash flows of forecasted transactions, as well as evaluate the probability of occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could affect the timing of recognition for changes in fair value of certain derivatives used as hedges. See *Market Rate Sensitive Instruments and Risk Management* in MD&A and Notes 2 and 11 to the Consolidated Financial Statements.

Accounting for gas and oil operations—The Company follows the full cost method of accounting for gas and oil exploration and production activities prescribed by the SEC. Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized and subsequently depreciated using a unit-of-production method. The depreciable base of costs includes estimated future costs to be incurred in developing proved gas and oil reserves, as well as dismantlement and abandonment costs, net of projected salvage values. The calculations under this accounting method are dependent on engineering estimates of proved reserve quantities and estimates of the amount and timing of future expenditures to develop the proved reserves. Proved reserves, and the cash flows related to these reserves, are estimated based on a combination of historical data and estimates of future activity. Actual reserve quantities and development expenditures may differ from the forecasted amounts. In addition, the Company has significant investments in unproved properties which are initially excluded from the depreciable base. Until the properties are evaluated, a ratable portion of the capitalized costs is periodically reclassified to the depreciable base, determined on a property by property basis, over terms of underlying leases. Once a property has been evaluated, any remaining capitalized costs are then transferred to the depreciable base. Capitalized costs in the depreciable base are subject to a ceiling test prescribed by the SEC. The test limits capitalized amounts to a ceiling—the present value of estimated future net revenue to be derived from the production of proved gas and oil reserves. The Company performs the test quarterly, on a country-by- country basis, and would recognize asset impairments to the extent that total capitalized costs exceed the ceiling. Any impairment of excess gas and oil property costs over the ceiling is charged to operations. Given the volatility of natural gas and oil prices, it is possible that the Company's estimate of discounted future net cash flows from proved natural gas and oil reserves could change in the near term. If natural gas or oil prices decline, even if for only a short period, or if the Company revises its estimated proved reserves downward, recognition of natural gas and oil property impairments could occur in the future. See Notes 2 and 26 to the Consolidated Financial Statements.

Use of estimates in impairment testing—The Company is required to test at least annually its goodwill for potential impairment. As part of that test, the Company is required to determine the fair value of its reporting units. The Company estimates the fair value of its reporting units using discounted cash flow analyses and other valuation techniques based on multiples of earnings for peer group companies and analyses of recent business combinations involving peer group companies. These calculations are dependent on many subjective factors, including the selection of appropriate discount and growth rates, the selection of peer group companies and recent transactions and management's estimate of future cash flows. The cash flow estimates used by the Company are based on the best information available at the time the estimates are made; however, estimates of future cash flows are by nature highly uncertain and may vary significantly from actual results.

The Company performed the transitional impairment test upon adoption of Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible Assets,* as of January 1, 2002 and its annual test later in the year. The fair value of each of the Company's reporting units exceeded the related carrying amounts, resulting in no impairment. The underlying assumptions and estimates involved in preparing these fair value calculations could change significantly from period to period. If the Company's estimates of the fair value of its reporting units are substantially reduced, impairment may be indicated and the Company would be required to perform the second step of the goodwill impairment test. That step measures the amount of impairment, if any, and requires the further use of fair value estimates. A goodwill impairment charge would result in a charge to earnings, with a corresponding reduction of the carrying amount of goodwill on the balance sheet. The Company had $625 million and $519 million of goodwill at December 31, 2002 and 2001, respectively. See Notes 2 and 13 to the Consolidated Financial Statements for further discussion of goodwill impairment tests.

Impairment testing for long-lived assets and intangible assets with definite lives is required when circumstances indicate that such assets may be impaired. In performing the impairment test, the Company would estimate the future cash flows associated with individual assets or groups of assets. Impairment results when the undiscounted estimated future cash flows are less than the related asset's carrying amount. If impaired, the asset must be written down to its fair value, which is generally calculated using the present value of its expected future net cash flows, using an appropriate discount rate. Although cash flow estimates used by the Company are based on the best information available at the time the estimates are made, estimates of future cash flows are by nature highly uncertain and may vary significantly from actual results.

Accounting for regulated operations—Methods of allocating costs to accounting periods for operations subject to federal or state cost-of-service rate regulation may differ from accounting methods generally applied by nonregulated companies. When the timing of cost recovery prescribed by regulatory authorities differs from the timing of expense recognition used for accounting purposes, the Company's Consolidated Financial Statements may recognize a regulatory asset for expenditures that otherwise would be expensed, based on the approval from the appropriate regulatory authority. Regulatory assets represent probable future revenue associated with certain costs that will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenue associated with expected customer credits through rates. Management makes assumptions regarding the probability of regulatory asset recovery through future rates approved by applicable regulatory authorities. The expectations of future recovery are generally based upon historical experience, as well as discussions with applicable regulatory authorities. If recovery of regulatory assets is determined to be less than probable, they would be expensed in the period such assessment is made. See Notes 2 and 14 to the Consolidated Financial Statements.

Results of Operations

The Company's discussion of its results of operations includes a tabular summary of contributions by its operating segments to net income, an overview of consolidated results of operations and a more detailed discussion of the results of segment operations.

	Year Ended December 31,								
	Net Income			Operating Revenue			Operating Expenses		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
	(Millions)								
Delivery	$168	$ 148	$ 144	$1,247	$1,747	$1,985	$ 971	$1,484	$1,719
Energy	205	167	147	1,479	1,650	1,250	1,137	1,363	994
Exploration & Production	256	202	138	1,320	1,009	979	866	674	736
Corporate and Other	9	(126)	(185)	6	49	150	8	201	429
Eliminations	—	—	—	(152)	(218)	(349)	(152)	(218)	(342)
Total—Consolidated	$638	$ 391	$ 244	$3,900	$4,237	$4,015	$2,830	$3,504	$3,536

Overview of Consolidated Operating Results

Net income in 2002 was $638 million, an increase of $247 million, as compared with net income of $391 million in 2001. The operating results of 2002, as compared to 2001, reflected higher gas and oil production revenue, attributable to the full year operations of Dominion Oklahoma Texas Exploration & Production, Inc. (DOTEPI) (see Note 5 to the Consolidated Financial Statements), the Company's ongoing drilling programs, and lower operating expenses, principally in purchased gas costs, partially offset by natural production declines, and by the effects of lower regulated gas distribution service revenue and lower nonregulated gas sales. The increased 2002 operating results also reflected the impacts of the following 2001 charges: a $22 million ($14 million after taxes) cumulative effect of a change in accounting principle related to the adoption of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (see Note 11 to the Consolidated Financial Statements); $108 million ($69 million after taxes) in connection with the impairment of forward natural gas contracts due to reorganization of Enron Corp. and certain of its subsidiaries (collectively referred to as Enron) under Chapter 11 bankruptcy proceedings (see Note 11 to the Consolidated Financial Statements); and the restructuring and other merger-related costs totaling $45 million ($31 million after taxes) (see Notes 5 and 7 to the Consolidated Financial Statements). In addition, the Company's effective income tax rate decreased in 2002, reflecting the $16 million net effect, allocated to the Company, of including certain subsidiaries in Dominion's consolidated state income tax returns (see Note 9 to the Consolidated Financial Statements).

Total operating revenue was $3.9 billion in 2002, a decrease of $337 million from $4.2 billion in 2001. Regulated gas sales and gas transport service revenue combined, decreased $514 million, as compared to 2001. Lower regulated gas sales volumes reflected customers opting for alternate suppliers under the Energy Choice programs, offset by the effect of cooler weather experienced in the franchise service areas. Nonregulated gas sales revenue decreased $172 million, as compared to 2001, reflecting both lower sales volumes due to lower activity and lower prices. Gas and oil production revenue increased $284 million, attributable to the full year operations of DOTEPI and the Company's ongoing drilling programs, partially offset by natural production declines.

Total operating expense was $2.8 billion in 2002, a decrease of $674 million as compared to $3.5 billion in 2001. Purchased gas, the largest expense category for the Company, represents volumes purchased to meet sales requirements for regulated and nonregulated operations. This expense is influenced primarily by changes in regulated gas sales requirements, the price of gas supplies and the timing of recoveries of deferred purchased gas costs by the rate-regulated subsidiaries. Purchased gas costs decreased $670 million, as compared to 2001, reflecting lower purchased gas prices resulting from lower overall market prices and lower volume requirements. Other operations and maintenance expense was lower in 2002, reflecting a decrease in 2002 salary expense, an overall reduction in 2002 operating costs and the 2001 charge related to the impairment of Enron natural gas contracts. The lower other operations and maintenance expense was offset by the effects of higher depreciation, depletion and amortization expense, due primarily to higher levels of gas and oil production resulting from DOTEPI's full year operations and the Company's ongoing drilling programs.

Segment Results

Due to the regulated nature of the Delivery segment and the transmission business of the Energy segment being subject to cost-of-service rate regulation, operating results can be affected by regulatory delays when price increases are sought through general rate filings to recover higher costs of operations. Weather is also an important factor since a major portion of the gas sold or transported by the distribution and transmission operations is ultimately used for space heating.

Delivery Segment

The Company's Delivery segment manages the Company's retail gas distribution systems and customer service operations. The Delivery segment includes the results of the Company's retail gas distribution subsidiaries: The East Ohio Gas Company (Dominion East Ohio), The Peoples Natural Gas Company (Dominion Peoples) and Hope Gas, Inc. (Dominion Hope). These subsidiaries sell gas and provide transportation services to residential, commercial and industrial customers in Ohio, Pennsylvania and West Virginia and are subject to price regulation by their respective state utility commissions.

Sales growth in the Company's residential service areas of Ohio, Pennsylvania and West Virginia has generally been limited since these areas have experienced minimal population growth, and the vast majority of households in these areas already use natural gas for space heating. Sales are being affected by regulatory and legislative initiatives to deregulate natural gas at the retail level. Similar to the unbundling of the services provided by gas pipeline companies, gas distribution companies are adapting to the deregulation and unbundling of the retail energy market. Under open access programs in Ohio and Pennsylvania, customers may now choose a gas supplier other than their local gas utility and have the local utility provide transportation of the commodity through its existing delivery system. Since the Company's retail gas distribution subsidiaries provide the transportation service to customers without regard to whether the gas is supplied by the Company or by an alternate supplier, the gas distribution subsidiaries' results of operations are generally not impacted by customers who choose alternate gas suppliers. For the Company's regulated gas sales, the cost of purchased gas is usually recovered from customers through rates, although certain rates may be subject to price caps, limiting recovery of higher costs in certain circumstances.

At December 31, 2002, approximately 647,000 of the Company's 1.2 million Ohio customers and approximately 106,000 residential and small commercial customers in the Company's Pennsylvania service area were participating in open-access and purchasing natural gas from other suppliers. Large industrial customers in Ohio also source their own natural gas supplies. Nearly all Pennsylvania industrial and large commercial customers buy natural gas from unregulated suppliers.

The following table presents summarized information relating to the Company's Delivery segment:

	Year Ended December 31,	
	2002	2001
	(Millions)	
Operating revenue	$1,247	$1,747
Operating expenses	971	1,484
Net income contribution	168	148
	(Billion Cubic Feet)	
Throughput:		
Gas sales	123	141
Gas transportation	241	216
Total throughput	364	357

Operating Results

The Delivery segment contributed $168 million to net income in 2002, as compared to $148 million in 2001. The 2002 results for the Delivery segment reflected lower regulated gas sales revenue, offset by the effects of higher transportation revenue, lower purchased gas costs and lower other operations and maintenance expense, as compared to 2001.

Total operating revenue of the Delivery segment decreased $500 million in 2002 from $1.7 billion in 2001. Regulated gas sales revenue was $876 million, a decrease of $533 million as compared to $1.4 billion in 2001. The lower regulated gas sales revenue in 2002, as compared to 2001, reflected a $370 million decrease due primarily to the pass through of lower purchased gas costs and a $163 million decrease due to lower sales volumes. The lower sales volumes reflected a $191 million decrease for the migration of customers, opting for alternate suppliers, from regulated gas sales to transportation service and lower levels of industrial activity, partially offset by a $28 million increase resulting from cooler weather experienced in the Company's retail service areas. The heating degree-days for 2002 were 4 percent higher than in 2001. Average sales rates for all customer groups decreased, reflecting the pass through of lower purchased gas costs. The higher gas transportation volumes in 2002 reflected the migration of residential and commercial customers from sales to transport service under the Energy Choice programs in Ohio and Pennsylvania.

Total operating expenses of the Delivery segment in 2002 were $971 million, a decrease of $513 million, as compared to 2001. Purchased gas costs decreased $489 million in 2002, reflecting lower purchased gas prices resulting from lower overall market prices and lower volume requirements. Other operations and maintenance expense was $31 million lower in 2002, as compared to 2001. The decrease in other operations and maintenance expense was due primarily to lower administrative and general salary expenses, reductions in materials and supplies and contractor services in 2002, partially offset by an increase in uncollectible accounts expense.

Throughput

Since Delivery sales volumes largely represent gas used for space heating, changes in volumes are primarily a function of the weather. In addition to sales of gas, Delivery provides gas transportation services to a wide range of customers, including residential, commercial and industrial end-users. Therefore, the volume of gas transported can be affected by the weather and by changes in both economic and market conditions. Both gas sales and transportation volumes are also being impacted by the migration of customers from sales to transport service under the Energy Choice programs.

Gas sales volumes were 123 billion cubic feet (bcf) in 2002, as compared to 141 bcf in 2001. The year-to-year comparison reflected decreased sales in 2002 due to the migration of customers from sales to transport under the Energy Choice programs, offset by the effect of cooler weather. Residential gas sales volumes decreased 12 bcf in 2002, to 94 bcf, while volumes transported for residential customers increased 16 bcf. Sales to commercial customers totaled 26 bcf in 2002, a decrease of 5 bcf from 2001, while volumes transported to these customers increased 6 bcf to 49 bcf. Total throughput to industrial customers was 110 bcf in 2002, as compared to 106 bcf in 2001.

Energy Segment

The Energy segment manages the Company's gas transmission pipeline, certain gas production, storage and by-product operations and energy marketing activities. The Energy segment includes Dominion Transmission, Inc. (Dominion Transmission), Dominion Field Services, Inc. (Dominion Field Services), Dominion Retail, Inc. (Dominion Retail) and other subsidiaries. Dominion Transmission, an interstate pipeline company regulated by the Federal Energy Regulatory Commission (FERC), provides gas transportation, storage and related services to affiliates, utilities and end-users in the Midwest, the Mid-Atlantic states and the Northeast. In addition, Dominion Transmission engages in gas and oil production activities in the Appalachian basin. Dominion Field Services is engaged in activities related to gathering and processing of Appalachian area natural gas supply and provides natural gas storage facilities services. Dominion Retail, a nonregulated company, markets natural gas, electricity and related products and services to residential, commercial and small industrial customers, including those within the Company's traditional retail service areas. Dominion Retail is expected to enable the Company to take advantage of emerging deregulated energy markets for both gas and electricity.

On September 5, 2002, the Company acquired 100 percent ownership of Cove Point LNG Limited Partnership (Dominion Cove Point), a cost-based rate-regulated entity, from a subsidiary of The Williams Companies. Dominion Cove Point's assets include a liquefied natural gas import facility located near Baltimore, Maryland that is under reconstruction, a liquefied natural gas storage facility and an approximately 85-mile natural gas pipeline. The Company expects Dominion Cove Point to become fully operational in 2003.

The following table presents summarized information relating to the Company's Energy segment:

	Year Ended December 31,	
	2002	2001
	(Millions)	
Operating revenue	$1,479	$1,650
Operating expenses	1,137	1,363
Net income contribution	205	167
	(Billion Cubic Feet)	
Gas sales	206	216
Gas transmission throughput	595	549

Operating Results

The Energy segment contributed $205 million to net income in 2002, as compared to $167 million in 2001. The 2002 results for the Energy segment reflected lower nonregulated gas sales and gas transportation revenue, offset by the effect of lower operating costs, principally in purchased gas costs, as compared to 2001.

Total operating revenue of the Energy segment was $1.5 billion in 2002, a decrease of $171 million, as compared to $1.7 billion in 2001. Nonregulated gas sales revenue was $811 million, decreasing $223 million from 2001, primarily as a result of lower sales prices, although sales volumes decreased by 10 bcf. The average sales price was $3.92 per thousand cubic feet (mcf) in 2002, as compared to $4.76 per mcf in 2001, resulting in a $186 million decrease in nonregulated gas sales revenue. Lower sales volumes resulted in a $37 million decrease in nonregulated gas sales revenue. Nonregulated electric sales revenue increased $89 million in 2002, as compared to 2001, reflecting $71 million of retail energy sales revenue and $18 million of revenue generated from the new power generation facility at the Company's Armstrong station in Pennsylvania. The facility became available for commercial operations during the second quarter of 2002, and the Company began operating the new facility under an operating lease with Dominion Equipment, Inc., a Dominion subsidiary. See Note 21 to the Consolidated Financial Statements. Revenue from natural gas by-products sales was $65 million in 2002, as compared to $70 million in 2001. The decrease reflected lower average sales prices for all by-products in 2002, partially offset by higher sales volumes. Gas transportation revenue was $316 million, a decrease of $24 million from 2001, primarily as a result of lower rates, partially offset by higher transportation volumes.

Total operating expenses of the Energy segment in 2002 was $1.1 billion, a decrease of $226 million, as compared to 2001. Purchased gas was the largest component of the operating expenses, decreasing $234 million to $769 million in 2002, reflecting the lower prices paid in 2002, as compared to 2001. Electric fuel energy purchases increased $62 million in 2002, as compared to 2001. Substantially all of the increase related to higher volumes purchased during 2002, reflecting the Company's energy marketing operations that are not subject to cost-based rate regulation. Liquids, pipeline capacity and other purchases decreased $50 million in 2002, as compared to 2001, primarily reflecting comparably lower levels of rate recoveries for certain costs of transmission operations in 2002. The difference between actual expenses and amounts recovered in the period are deferred, pending future rate adjustments. Other operations and maintenance expense was $10 million lower in 2002, as compared to 2001. The decrease in other operations and maintenance expense was due primarily to reduction in overall operating costs in 2002.

Exploration & Production Segment

The Exploration & Production segment manages the Company's onshore and offshore gas and oil exploration, development and production operations.

The Exploration & Production segment includes the results of Dominion Exploration & Production, Inc. (Dominion E&P). The activities of Dominion E&P are conducted primarily in the Gulf of Mexico, the Mid-Continent region, the Permian Basin, the Appalachian Basin and other selected regions in the continental United States. Effective January 1, 2001, Dominion E&P transferred its 21 percent interest in heavy oil producing properties in Alberta, Canada, to another subsidiary of Dominion. Proved reserves associated with the Canadian properties approximated 1 bcf of gas and 6.6 million barrels of oil at December 31, 2000. The property was transferred at a market value of $4.5 million. Also included in this segment are CNG Main Pass Gas Gathering Corporation and CNG Oil Gathering Corporation. These two subsidiaries hold equity investments in gas and oil gathering systems located in the Gulf of Mexico.

On November 1, 2001, Dominion acquired all of the outstanding shares of common stock of Louis Dreyfus Natural Gas Corp. (Louis Dreyfus), a natural gas and oil exploration and production company headquartered in Oklahoma City, Oklahoma (see Note 5 to the Consolidated Financial Statements). Dominion acquired Louis Dreyfus by merging it into a newly formed, wholly-owned subsidiary of Dominion, Dominion Oklahoma Texas Exploration & Production, Inc. (DOTEPI). Immediately after the merger, Dominion contributed DOTEPI to the Company. The results of DOTEPI have been included in the Consolidated Financial Statements since that date. The acquisition of DOTEPI doubled the Company's proved gas and oil reserves.

The following table sets forth information relating to the Company's Exploration & Production segment:

	Year Ended December 31,	
	2002	2001
	(Millions)	
Operating revenue	$1,320	$1,009
Operating expenses	866	674
Net income contribution	256	202
Production:		
Gas (bcf)	272	162
Oil (000 bbls)	8,520	5,914
Average realized prices with hedging results (in dollars):		
Gas (per mcf)	$ 3.60	$ 3.99
Oil (per bbl)	$23.72	$24.58
Average prices without hedging results (in dollars):		
Gas (per mcf)	$ 3.24	$ 4.06
Oil (per bbl)	$25.03	$24.71
Other Information (in dollars):		
DD&A (per mcfe)	$ 1.24	$ 1.24
Average production (lifting) cost (per mcfe)	$ .51	$ .49

bbl = barrel
bcf = billion cubic feet
mcf = thousand cubic feet
mcfe = thousand cubic feet equivalent

Operating Results

The Company's Exploration & Production segment contributed $256 million to net income in 2002, as compared to $202 million in 2001. The 2002 results for the Exploration & Production segment reflected higher gas and oil production levels, partially offset by lower average realized prices, including the results of hedging, higher depreciation, depletion and amortization, other operations and maintenance and interest expenses, as compared to the same period in 2001.

Total operating revenue of the Exploration & Production segment increased $311 million to $1.3 billion in 2002 . Gas and oil production revenue was $1.1 billion in 2002, increasing $283 million, as compared to $772 million in 2001, reflecting higher overall gas and oil production levels, offset by the effect of lower average realized prices. The $283 million increase included higher gas production revenue of $227 million, reflecting an increase of $349 million due to higher sales volumes, offset by the effect of lower realized prices of $122 million. Oil production revenue increased by $56 million, reflecting an increase of $57 million due to higher sales volumes, offset by the effect of lower realized prices of $1 million. The higher production levels were attributed to the full year operations of DOTEPI and the Company's ongoing drilling programs, partially offset by natural production declines. Revenue from gas and oil brokering activities was $247 million in 2002, an increase of $18 million from 2001, due primarily to higher transaction volumes, partially offset by lower prices realized from brokering activities.

Total operating expenses for 2002 were $866 million, as compared to $674 million in 2001. Higher operating costs included increases of $145 million in depreciation, depletion and amortization expense, reflecting the higher production levels from DOTEPI's full year operations and the Company's ongoing drilling programs, and $31 million in other taxes, as compared to 2001, due primarily to higher gross receipts taxes. Interest expense was $75 million in 2002, an increase of $30 million, as compared to 2001, primarily due to the full year operations of DOTEPI.

Corporate and Other Segment

	Year Ended December 31, 2002	2001
	(Millions)	
Net income (loss) contribution	$9	$(126)

The Corporate and Other segment includes the activities of CNG International and other minor subsidiaries, as well as costs of the Company's corporate functions and certain expenses that are not allocated to the operating segments. CNG International is engaged in energy-related activities outside the United States. However, the Company has decided to focus on the United States gas and oil markets and, accordingly, is pursuing the sale of CNG International (see Note 8 to the Consolidated Financial Statements).

The net income for the Corporate and Other segment for 2002 was $9 million, as compared to a $126 million loss in 2001. The increase in net income reflected higher equity investment earnings and the following charges:

- 2001 restructuring and other merger-related costs of $45 million ($31 million after taxes) (see Note 7 to the Consolidated Financial Statements);
- 2001 cumulative effect of adopting SFAS No. 133 of $22 million ($14 million after taxes) (see Note 11 to the Consolidated Financial Statements); and
- 2001 estimated impairment of natural gas contracts of $108 million ($69 million after taxes), resulting from the Company's exposure to Enron (see Note 11 to the Consolidated Financial Statements).

Contractual Obligations

Presented below is a summary of the Company's contractual obligations as of December 31, 2002. These items are discussed in Notes 16, 17 and 21 to the Consolidated Financial Statements.

	Payments Due By Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
	(Millions)				
Contractual Obligations:					
Long-term debt	$3,388	$150	$638	$700	$1,900
Trust preferred securities	200	—	—	—	200
Lease obligations	197	32	65	54	46
Fuel and other commitments	808	172	215	138	283
Total	$4,593	$354	$918	$892	$2,429

The Company expects to fund these obligations and commitments with cash flows from operations and short-term borrowings. These amounts do not include planned capital expenditures or working capital commitments, such as the repayment of short-term debt and settlement of derivative contracts or amounts for interest or distributions payable on securities issued by the Company.

Future Issues and Outlook

Regulated Gas Distribution Operations

Gas Deregulation Legislation

Each of the three states in which the Company has gas distribution operations has enacted or considered legislation regarding deregulation of natural gas sales at the retail level.

Ohio—Ohio has not enacted legislation requiring supplier choice for residential and commercial natural gas consumers. However, in cooperation with the Public Utilities Commission of Ohio (Ohio Commission), the Company, on its own initiative, offers retail choice to customers. At December 31, 2002, approximately 647,000 of the Company's 1.2 million Ohio customers were participating in this open-access program. Large industrial customers in Ohio also source their own natural gas supplies.

In November 2002, the Company filed proposed tariffs to comply with the Ohio Commission's rules that implement House Bill 9. House Bill 9 establishes minimum standards for suppliers and aggregators participating in natural gas customer choice programs. The Ohio Commission has not acted on any of the tariff filings made or given any indication as to when such action can be expected.

Pennsylvania—At December 31, 2002, approximately 106,000 residential and small commercial customers had opted for Energy Choice in the Company's Pennsylvania service area. Nearly all Pennsylvania industrial and large commercial customers buy natural gas from unregulated suppliers.

West Virginia—At this time, West Virginia has not enacted legislation to require customer choice in its retail natural gas markets. However, the West Virginia Public Service Commission (West Virginia Commission) has issued regulations to govern pooling services, one of the tools that natural gas suppliers may utilize to provide retail customer choice in the future. In addition, the West Virginia Commission is developing rules for a code of conduct between utilities and their marketing affiliates, as well as Consumer Protection regulations and Marketer Licensing Rules. In 2002, the West Virginia Commission proposed rules that require that competitive gas service providers be licensed in West Virginia.

Rate Matters—Gas Distribution

When necessary, the Company's gas distribution subsidiaries in Ohio, Pennsylvania and West Virginia seek general rate increases on a timely basis to recover increased operating costs and to ensure that rates of return are compatible with the cost of raising capital. In addition to general rate increases, certain gas distribution subsidiaries make routine separate filings with their respective state regulatory commissions to reflect changes in the costs of purchased gas. These purchased gas costs are recovered through a mechanism that ensures dollar for dollar recovery of prudently incurred costs. Costs incurred that are expected to be recovered in future rates are deferred as regulatory assets.

Ohio—In December 2002, the Ohio Commission conditionally approved an earlier application by the Company to implement a four-month Gas Cost Recovery (GCR) rate. The Ohio Commission approved the adjustment components of the GCR and directed the Company to leave the Expected Gas Cost portion of the GCR at the previous level for one more month before filing for a new three-month rate.

In January 2003, the Ohio Commission approved the settlement of the Company's 2001 GCR financial and management performance audit. The settlement contained no disallowances and provided for a review of the corporate gas supply group expense recovery through the GCR and an internal audit of gas procurement processes and affiliate company gas purchase transactions.

In February 2002, the Company filed a report with the Ohio Commission that addressed the results of a payment matching program approved by the Ohio Commission in 2001 and deferral of certain uncollectible residential customer receivables in excess of the amount already recovered in rates. The report required no action by the Ohio Commission. Recovery of the deferred amount will be requested in the Company's next rate case. The Company believes that it will recover those amounts deferred.

Pennsylvania—The Pennsylvania Public Utility Commission (Pennsylvania Commission) accepted a settlement filed by the Company and other parties to the Company's gas cost recovery proceeding in September 2002. No disallowances were incurred as part of the settlement.

West Virginia—In 2001, the West Virginia Commission approved a settlement between the Company and certain third parties, regarding the costs of gas supplies and increased operating costs. The settlement stipulated that the Company would receive a $9.5 million increase in gas and non-gas revenue and also provides for a two-year rate moratorium. The new rates took effect on January 1, 2002 and will be in place through December 31, 2003.

Interstate Gas Transmission Operations

FERC Policy Developments

In October 2002, FERC hosted a public policy conference regarding various short and long-term issues that impact federal regulation of the natural gas industry. Among other issues, FERC examined supply and demand forecasts, the adequacy of natural gas infrastructure, regulatory policies applicable to liquefied natural gas (LNG) facilities, offshore gathering policies and the flexibility of interstate pipeline operations. As a result, FERC is considering adjustments to its future regulatory policies concerning the natural gas industry, including modification of its approach to regulation of LNG projects. The policy change is intended to encourage additional development of LNG terminals and to increase the availability of imported gas supplies.

FERC also continues to pursue a rulemaking that will eliminate the separate standards of conduct regulations for natural gas pipelines and electric transmission utilities and replace these requirements with uniform standards applicable to interstate "Transmission Providers." The proposed standards would redefine the scope of affiliates covered by standards of conduct for most FERC-regulated companies. If the proposed policy is adopted, it will supersede the existing standards, that are applicable to the Company. The Company supports the policy goal to ensure competitive interstate energy markets; however, the Company has advocated adjustments to the proposed rules. The Company anticipates further action by FERC in early 2003. While the Company expects the outcome of a final rule to improve its ability to compete with similarly-situated transmission providers, it does not expect a final rule to have a short-term material impact on its results of operations, financial position or cash flows.

Rate Matters—Gas Transmission

The Company implemented various rate filings, tariff changes and negotiated rate service agreements for its FERC-regulated businesses during 2002. In all material respects, these filings were approved by FERC in the form requested by the Company and were subject to only minor modifications. The Company has no significant rate matters pending before FERC at this time.

Exploration and Production Operations

Dominion continues to focus on increasing earnings from gas and oil properties primarily through acquisition and development activities, exploration and operating efficiencies. The November 2001 acquisition of Louis Dreyfus represented the addition of significant, long-lived natural gas reserves located in several onshore United States regions serving Northeast markets. This addition also provided significant new development drilling opportunities, complementing the Company's existing development and exploration activities. The emphasis toward increased acquisition and development activities, as a complement to the higher risk exploration program, was further supported by the 2002 purchase of several onshore properties having additional development drilling and production enhancement potential.

Pipeline Operations

The Company plans to expand its natural gas transmission system with a $497 million, 279-mile interstate pipeline. The 279-mile Greenbrier Pipeline is planned to originate in Kanawha County, West Virginia and extend to Granville County, North Carolina. The Company owns 67 percent of Greenbrier Pipeline Company, LLC, with Piedmont Natural Gas owning the remaining 33 percent. In October 2002, FERC gave preliminary approval for the proposed project.

Environmental Matters

The Company is subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. The Company also may seek recovery through regulated rates for environmental expenditures related to regulated gas transmission and distribution operations. See Note 21 to the Consolidated Financial Statements for additional discussion of environmental matters.

Although the Company is routinely engaged in environmental protection and monitoring efforts, the cost of such activities was not material in 2002 and 2001. Furthermore, the Company expects no material expenditures in 2003.

Accounting Matters

The FASB has issued several new standards that will affect the Company beginning in 2003. These include: SFAS No. 143, *Accounting for Asset Retirement Obligations;* Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others—An Interpretation of FASB Statements No. 5, 57 and 107*; and Interpretation No. 46, *Consolidation of Variable Interest Entities*. See Note 4 to the Consolidated Financial Statements for further discussion of the impact of adopting these new accounting standards and information about other standard-setting activities.

Outlook for 2003

The Company believes its operating businesses will provide a stable contribution to net income in 2003, with future growth in 2004. However, the Company's earnings for 2003 will include the effects of the following items: severance costs under *Workforce Reductions* discussed below and the cumulative effect of implementing a change in the accounting for asset retirement obligations (see Note 4 to the Consolidated Financial Statements). The 2003 projections for the Company's operating businesses anticipate higher sales of gas and oil, reflecting continued growth in production and higher realized prices and lower pension benefit credits.

Other Matters

Pension Costs

As discussed in Note 20 to the Consolidated Financial Statements, the Company maintains qualified noncontributory defined benefit retirement plans for employees represented by recognized bargaining units of the Company's subsidiaries. In addition, the Company's employees not represented by bargaining units participate in the Dominion pension plan, which provides benefits to employees of multiple Dominion subsidiaries. Prior to 2002, the Company maintained a qualified pension plan for such employees; however, it was merged with the Dominion pension plan in 2002. The Company will recognize its allocated share of net periodic pension credits from the Dominion pension plan. Investment experience and market conditions, including interest rates, impact the measurement of these benefit obligations and the cost of providing such benefits. Accordingly, assumptions for discount rates and the expected long-term rate of return on investments are important considerations under SFAS No. 87, *Employers' Accounting for Pensions.* However, since the objective of SFAS No. 87 is to recognize the cost of providing benefits over employees' service period, it permits the delayed recognition of certain elements of retirement plan results.

Dominion, on behalf of its subsidiaries, including the Company, has reviewed the assumption used for the expected long-term rate of return on plan assets to better reflect anticipated future market conditions and has adopted an expected rate of 8.75 percent for 2003. This change, combined with other factors, such as a revised discount rate assumption of 6.75 percent for 2003, will reduce the Company's allocable portion of 2003 pension credits from the Dominion pension plan, as well as the 2003 pension credits related to retirement plans for employees of the Company's subsidiaries represented by recognized bargaining units, by an estimated $39 million, as compared to 2002.

Workforce Reductions

In connection with a plan announced by Dominion in January 2003, the Company expects to eliminate some union and salaried positions during 2003. The workforce reductions will affect primarily support positions. Affected workers will be offered severance packages, and benefits for union workers will be negotiated during 2003. Pending completion of the process to identify affected positions, the Company has not estimated the cost of the workforce reductions.

Expiration of Section 29 Tax Credits

Internal Revenue Code Section 29, "Credit for the Production of Fuel from Nonconventional Sources" (also referred to as the production tax credit), allows income tax credits for certain qualified production, including some natural gas, sold before January 1, 2003. Congress has not acted on legislation to extend this credit beyond 2002 for most qualified production. Whether Congress will take any action during the current term to extend the credit is uncertain. Dominion utilized approximately $10 million of these credits for the year ended December 31, 2002.

Effect of Changes in Commodity Prices

The Company's operations are impacted by changes in energy commodity prices. When energy commodities are sold by one of the Company's utilities subject to cost-of-service rate regulation, commodity costs are generally recovered through rates. Market price changes impact the Company's revenue from natural gas and oil production and from commodity sales through unregulated subsidiaries. Dominion has established an enterprise risk management function to evaluate these risks and to recommend actions to management that are intended to mitigate such risks.

Market Rate Sensitive Instruments and Risk Management

The Company's financial instruments, commodity contracts and related derivative instruments are exposed to potential losses due to adverse changes in interest rates and commodity prices as described below. Interest rate risk generally is related to the Company's outstanding debt. Commodity price risk is present in the Company's gas production and procurement operations and energy marketing operations due to the exposure to market shifts for prices received and paid for natural gas and oil. The Company uses derivative instruments to manage price risk exposures for these operations.

The Company's sensitivity analysis estimates the potential loss of future earnings or fair value from market risk sensitive instruments over a selected time period due to a 10 percent unfavorable change in interest rates and commodity prices.

Commodity Price Risk

The Company manages the price risk associated with purchases and sales of natural gas and oil by using derivative commodity instruments, including futures, forwards, options and swaps.

For sensitivity analysis purposes, the fair value of the Company's derivative commodity instruments is determined based on models that consider the market prices of commodities in future periods, the volatility of the market prices in each period, as well as the time value factors of the derivative instruments. Market prices and volatility are principally determined based on quoted prices on the futures exchange.

A hypothetical 10 percent unfavorable change in market prices of the Company's derivative commodity instruments would have resulted in a decrease in fair value of approximately $347 million and $156 million as of December 31, 2002 and 2001, respectively.

The impact of a change in energy commodity prices on the Company's derivative commodity instruments at a point in time is not necessarily representative of the results that will be realized when such contracts are ultimately settled. Net losses from derivative commodity instruments used for hedging purposes, to the extent realized, are generally offset by recognition of the hedged transaction, such as revenue from sales.

Interest Rate Risk

The Company manages its interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. The Company enters into interest rate sensitive derivatives, including interest rate swap agreements. For financial instruments outstanding at December 31, 2002, a hypothetical 10 percent increase in market interest rates would decrease annual earnings by approximately $2 million. A hypothetical 10 percent increase in market interest rates, as determined at December 31, 2001, would have resulted in a decrease in annual earnings of approximately $2 million.

Investment Price Risk

The Company sponsors employee pension and other postretirement benefit plans and participates in plans sponsored by Dominion that hold investments in trusts to fund benefit payments. To the extent that the values of investments held in these trusts decline, the effect will be reflected in the Company's recognition of the periodic cost of such employee benefit plans and the determination of the amount of cash to be contributed by the Company to the employee benefit plans.

Risk Management Policies

The Company has operating procedures in place that are administered by experienced management to help ensure that proper internal controls are maintained. In addition, Dominion has established an independent function at the corporate level to monitor compliance with the risk management policies of all subsidiaries. Dominion maintains credit policies that include the evaluation of a prospective counterparty's financial condition, collateral requirements where deemed necessary, and the use of standardized agreements which facilitate the netting of cash flows associated with a single counterparty. In addition, Dominion also monitors the financial condition of existing counterparties on an ongoing basis.

Management believes, based on Dominion's credit policies and the Company's December 31, 2002 provision for credit losses, that it is unlikely that a material adverse effect on its financial position, results of operations or cash flows would occur as a result of counterparty nonperformance. See Note 11 to the Consolidated Financial Statements for a discussion of the effects of Enron's bankruptcy on the Company's Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

See *Risk Factors and Cautionary Statements That May Affect Future Results* and *Market Rate Sensitive Instruments and Risk Management* in Management's Discussion and Analysis of Results of Operations.

Item 8. Financial Statements and Supplementary Data

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Report of Management

The Company's management is responsible for all information and representations contained in the Consolidated Financial Statements and other sections of the Company's annual report on Form 10-K. The Consolidated Financial Statements, which include amounts based on estimates and judgments of management, have been prepared in conformity with accounting principles generally accepted in the United States of America. Other financial information in the Form 10-K is consistent with that in the Consolidated Financial Statements.

Management maintains a system of internal controls designed to provide reasonable assurance, at a reasonable cost, that the Company's assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. Management recognizes the inherent limitations of any system of internal control and, therefore, cannot provide absolute assurance that the objectives of the established internal controls will be met. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel, and internal audits. Management believes that during 2002 the system of internal control was adequate to accomplish the intended objectives.

The Consolidated Financial Statements have been audited by Deloitte & Touche LLP, independent auditors, who have been engaged by the Board of Directors. Their audits were conducted in accordance with auditing standards generally accepted in the United States of America and included a review of the Company's accounting systems, procedures and internal controls to the extent necessary for the purpose of its report.

The Audit Committee of the Board of Directors of Dominion Resources, Inc. (the Company's parent), composed entirely of directors who are not officers or employees of Dominion Resources, Inc. or its subsidiaries, meets periodically with the independent auditors, the internal auditors and management to discuss auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities. Both the independent auditors and the internal auditors periodically meet alone with the Audit Committee and have free access to the Committee at any time.

Consolidated Natural Gas Company

/s/ THOMAS N. CHEWNING	/s/ STEVEN A. ROGERS
Thomas N. Chewning Executive Vice President and Chief Financial Officer	Steven A. Rogers Vice President and Controller *(Principal Accounting Officer)*

Independent Auditors' Report

To the Board of Directors of
Consolidated Natural Gas Company
Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Consolidated Natural Gas Company (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of income, comprehensive income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Consolidated Natural Gas Company and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 13 to the consolidated financial statements, effective January 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*. As discussed in Note 11 to the consolidated financial statements, effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. Also, as discussed in Note 3 to the consolidated financial statements, the Company changed its method of accounting used to develop the market-related value of pension plan assets in 2000.

/s/ Deloitte & Touche LLP

Richmond, Virginia
January 21, 2003

Consolidated Natural Gas Company
Consolidated Statements of Income

	Year Ended December 31,		
	2002	2001	2000
		(Millions)	
Operating Revenue	$3,900	$4,237	$4,015
Operating Expenses			
Purchased gas, net	1,247	1,917	1,705
Electric fuel energy purchases	103	68	19
Liquids, pipeline capacity and other purchases	156	201	309
Restructuring and other merger-related costs	(2)	45	270
Other operations and maintenance	570	705	591
Depreciation, depletion and amortization	554	407	442
Other taxes	202	161	200
Total operating expenses	2,830	3,504	3,536
Income from operations	1,070	733	479
Other income (loss):			
Gain on sale of subsidiary	—	—	163
Loss on net assets held for sale	—	—	(152)
Other	35	27	32
Total other income	35	27	43
Interest and related charges:			
Interest expense, net	136	156	162
Distributions—preferred securities of subsidiary trust	19	—	—
Total interest and related charges	155	156	162
Income before income taxes	950	604	360
Income taxes	312	199	147
Income before cumulative effect of changes in accounting principle	638	405	213
Cumulative effect of changes in accounting principle (net of income taxes of $8 in 2001 and $11 in 2000)	—	(14)	31
Net Income	$ 638	$ 391	$ 244

The accompanying notes are an integral part of the Consolidated Financial Statements.

Consolidated Natural Gas Company
Consolidated Balance Sheets

	At December 31, 2002	At December 31, 2001
	(Millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 22	$ 53
Accounts receivable:		
Customers (less allowance for doubtful accounts of $50 in 2002 and $52 in 2001)	662	594
Other	25	32
Receivables and advances due from affiliates	96	155
Inventories:		
Materials and supplies	29	24
Gas stored—current portion	86	122
Derivative assets	181	289
Deferred income taxes	—	107
Prepayments	114	174
Assets held for sale	145	76
Other	197	82
Total current assets	1,557	1,708
Investments	245	237
Property, Plant and Equipment		
Property, plant and equipment	14,119	12,417
Less accumulated depreciation, depletion and amortization	5,552	5,093
Total property, plant and equipment, net	8,567	7,324
Deferred Charges and Other Assets		
Goodwill, net	625	519
Intangible assets, net	104	115
Regulatory assets, net	265	267
Prepaid pension cost	738	568
Derivative assets	35	200
Other	85	89
Total deferred charges and other assets	1,852	1,758
Total assets	$12,221	$11,027

The accompanying notes are an integral part of the Consolidated Financial Statements.

Consolidated Natural Gas Company
Consolidated Balance Sheets (Continued)

	At December 31, 2002	At December 31, 2001
	(Millions)	
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Securities due within one year	$ 150	$ —
Short-term debt	397	776
Accounts payable, trade	601	577
Payables to affiliates	102	312
Short-term borrowings from parent	563	—
Accrued interest, payroll and taxes	193	186
Regulatory liabilities, net	34	134
Derivative liabilities	442	205
Other	241	336
Total current liabilities	2,723	2,526
Long-Term Debt	3,309	3,445
Deferred Credits and Other Liabilities		
Deferred income taxes	1,648	1,566
Deferred investment tax credits	14	16
Derivative liabilities	382	132
Other	129	139
Total deferred credits and other liabilities	2,173	1,853
Total liabilities	8,205	7,824
Commitments and Contingencies (see Note 21)		
Company Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust*	200	200
Minority Interest	7	3
Common Shareholder's Equity		
Common stock, no par value, 100 shares authorized and outstanding	1,816	1,816
Other paid-in capital	1,871	936
Accumulated other comprehensive income (loss)	(298)	82
Retained earnings	420	166
Total common shareholder's equity	3,809	3,000
Total liabilities and shareholder's equity	$12,221	$11,027

* As described in Note 17 to the Consolidated Financial Statements, the debt securities issued constitute 100 percent of the Trust's assets.

The accompanying notes are an integral part of the Consolidated Financial Statements.

Consolidated Natural Gas Company
Consolidated Statements of Common Shareholder's Equity

	Common Stock		Treasury Stock	Other Paid-In	Accumulated Other Comprehensive	Retained	
	Shares	Amount	Amount*	Capital	Income (Loss)	Earnings	Total
				(Millions)			
Balance at December 31, 1999	96	$ 264	$ (1)	$ 567	$ (4)	$ 1,550	$2,376
Merger with Dominion	(96)	2,163	—	(526)	—	(1,637)	—
Retirement of treasury stock	—	—	1	(1)	—	—	—
Comprehensive income	—	—	—	—	3	244	247
Dividends and other adjustments	—	(611)	—	—	—	(46)	(657)
Balance at December 31, 2000	— **	1,816	—	40	(1)	111	1,966
Acquisition of Louis Dreyfus	—	—	—	894	—	—	894
Tax benefit of stock option exercise	—	—	—	2	—	—	2
Comprehensive income	—	—	—	—	83	391	474
Dividends and other adjustments	—	—	—	—	—	(336)	(336)
Balance at December 31, 2001	— **	1,816	—	936	82	166	3,000
Equity contribution by parent	—	—	—	932	—	—	932
Tax benefit of stock option exercise	—	—	—	3	—	—	3
Comprehensive income (loss)	—	—	—	—	(380)	638	258
Dividends and other adjustments	—	—	—	—	—	(384)	(384)
Balance at December 31, 2002	— **	$1,816	$—	$1,871	$(298)	$ 420	$3,809

* Treasury stock share amounts were not material.

** Following the merger with Dominion, 100 shares of common stock, no par value, were issued and outstanding.

The accompanying notes are an integral part of the Consolidated Financial Statements.

Consolidated Natural Gas Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2002	2001	2000
		(Millions)	
Net income	$ 638	$ 391	$244
Other comprehensive income, net of taxes:			
Net deferred gains (losses) on derivatives—hedging activities, net of tax (expense) benefit of $194 in 2002 and $(131) in 2001	(382)	227	—
Unrealized losses on investment securities, net of tax benefit of $0.5	(1)	—	—
Foreign currency translation adjustments	—	—	(1)
Minimum pension liability adjustment, net of tax expense of $(0.5)	1	—	—
Cumulative effect of a change in accounting principle, net of tax benefit of $57	—	(105)	—
Amounts reclassified to net income:			
Net (gains) losses on derivatives—hedging activities*, net of tax expense (benefit) of $(0.5) in 2002 and $23 in 2001	2	(39)	—
Foreign currency translation adjustments	—	—	4
Other comprehensive income	(380)	83	3
Comprehensive income	$ 258	$ 474	$247

Amounts shown for Other Comprehensive Income are net of tax, except for foreign currency translation.

* As described in Note 11 to the Consolidated Financial Statements, $53 million was reclassified to offset an impairment of gas and oil producing properties in 2001.

The accompanying notes are an integral part of the Consolidated Financial Statements.

Consolidated Natural Gas Company
Consolidated Statements of Cash Flows

	2002	2001	2000
	Year Ended December 31,		
	(Millions)		
Operating Activities			
Net income	$ 638	$ 391	$ 244
Adjustments to reconcile net income to net cash from operating activities:			
Cumulative effect of changes in accounting principle, net of income taxes	—	14	(31)
Impairment loss on assets held for sale	—	—	152
Sale of Virginia Natural Gas	—	—	(168)
Depreciation, depletion and amortization	554	407	442
Deferred income taxes and investment tax credits, net	393	72	27
Changes:			
Accounts receivable	(62)	406	(395)
Receivables and advances due from affiliates	(1)	(166)	28
Inventories	33	(43)	(12)
Deferred purchased gas costs, net	(125)	348	(232)
Margin deposit assets and liabilities	(120)	352	(251)
Prepaid pension cost	(170)	(134)	(179)
Accounts payable, trade	19	(213)	382
Payables to affiliates	(154)	287	(27)
Accrued interest, payroll and taxes	8	(72)	71
Other, net	123	(125)	217
Net cash provided by operating activities	1,136	1,524	268
Investing Activities			
Plant construction and other property additions:			
Gas and oil exploration and production assets	(1,336)	(741)	(218)
Other	(349)	(415)	(543)
Proceeds from sale of Virginia Natural Gas	—	—	532
Proceeds from sale of Argentine investments	—	—	145
Acquisition of Louis Dreyfus, net of cash acquired	—	(902)	—
Acquisition of Dominion Cove Point, net of cash acquired	(225)	—	—
Other	55	(50)	2
Net cash used in investing activities	(1,855)	(2,108)	(82)
Financing Activities			
Issuance of preferred securities of subsidiary trust	—	200	—
Issuance of long-term debt	—	1,439	—
Repayment of long-term debt	(6)	(291)	(45)
Short-term borrowings from parent, net	1,463	—	—
Issuance (repayment) of short-term debt, net	(379)	(435)	527
Dividends paid	(384)	(336)	(704)
Other	(6)	2	—
Net cash provided by (used in) financing activities	688	579	(222)
Decrease in cash and cash equivalents	(31)	(5)	(36)
Cash and cash equivalents at beginning of the year	53	58	94
Cash and cash equivalents at end of the year	$ 22	$ 53	$ 58
Supplemental Cash Flow Information			
Net cash paid (received) during the year for:			
Interest and related charges, excluding capitalized amounts	$ 138	$ 137	$ 164
Income taxes	(62)	139	103
Noncash transactions from investing activities:			
Dominion's contribution of Louis Dreyfus	—	894	—
Transfer of split dollar life insurance policies to Dominion	—	56	—
Noncash transaction from financing activities:			
Conversion of short-term borrowings and other amounts payable to parent to other paid-in capital	932	—	—

The accompanying notes are an integral part of the Consolidated Financial Statements.

Consolidated Natural Gas Company
Notes to Consolidated Financial Statements

Note 1. Nature of Operations

Consolidated Natural Gas Company (CNG or the Company), a public utility holding company registered under the Public Utility Holding Company Act of 1935 (1935 Act), is a wholly-owned subsidiary of Dominion Resources, Inc. (Dominion). The Company, through its subsidiaries, operates in all phases of the natural gas business, explores for and produces gas and oil and provides a variety of energy marketing services. Its regulated retail gas distribution subsidiaries serve approximately 1.7 million residential, commercial and industrial gas sales and transportation customers in Ohio, Pennsylvania and West Virginia. Its interstate gas transmission pipeline system services each of its distribution subsidiaries, non-affiliated utilities and end-users in the Midwest, Mid-Atlantic states and the Northeast. The Company's exploration and production operations are located in several major gas and oil producing basins in the lower 48 states, including the outer continental shelf and deep-water areas of the Gulf of Mexico. The Company also provides a variety of energy marketing services and activities.

The Company's retail gas distribution subsidiaries include The East Ohio Gas Company (Dominion East Ohio), The Peoples Natural Gas Company (Dominion Peoples) and Hope Gas, Inc. (Dominion Hope). These subsidiaries sell gas and provide transportation services to residential, commercial and industrial customers in Ohio, Pennsylvania and West Virginia, and are subject to price regulation by their respective state utility commissions.

Dominion Transmission, Inc. (Dominion Transmission) operates a regional interstate pipeline system, regulated by the Federal Energy Regulatory Commission (FERC), that provides gas transportation and storage services to each of the Company's retail gas distribution subsidiaries and to nonaffiliated pipeline, utility and end-user customers in the Midwest, the Mid-Atlantic states and the Northeast. Dominion Transmission also holds a 24.72 percent partnership interest in the Iroquois Gas Transmission System, L.P., a limited partnership that owns and operates an interstate natural gas pipeline that transports Canadian gas to utility and power generation customers in New York and New England.

Dominion Exploration & Production, Inc. (Dominion E&P) explores for and produces gas and oil in several major producing basins in the lower 48 states, including the outer continental shelf and deep-water areas of the Gulf of Mexico. CNG Main Pass Gas Gathering Corporation (CNG Main Pass Gas Gathering) and CNG Oil Gathering Corporation (CNG Oil Gathering) hold 13.6 percent and 33.3 percent, respectively, partnership interests in gas and oil gathering systems located in the Gulf of Mexico.

Dominion Field Services, Inc. (Dominion Field Services) is engaged in activities related to the Appalachian area natural gas supply and provides natural gas storage facilities, services and other activities of a full-service gas storage business. Dominion Retail, Inc. (Dominion Retail) pursues opportunities arising from the deregulation of the energy industry at the retail level. Dominion Products and Services, Inc. (Dominion Products and Services) provides certain energy-related services to customers of the Company's retail gas distribution subsidiaries and others.

CNG International Corporation (CNG International) holds investments in energy-related activities outside the United States. In addition, CNG International was involved in the development and operation of a 26-megawatt power plant located on the island of Kauai, Hawaii. In 2000, management committed to a plan of disposal for CNG International. See Note 8 for more information.

On September 5, 2002, the Company acquired 100 percent ownership of Cove Point LNG Limited Partnership (Dominion Cove Point), a cost-based rate-regulated entity, from a subsidiary of The Williams Companies. Dominion Cove Point's assets include a liquefied natural gas import facility located near Baltimore, Maryland that is under reconstruction, a liquefied natural gas storage facility and an approximately 85-mile natural gas pipeline. The Company expects Dominion Cove Point to become fully operational in 2003. Dominion Cove Point is included in the Company's Energy operating segment.

On November 1, 2001, Dominion acquired all of the outstanding shares of common stock of Louis Dreyfus Natural Gas Corp. (Louis Dreyfus), a natural gas and oil exploration and production company headquartered in Oklahoma City, Oklahoma. Dominion acquired Louis Dreyfus by merging it into a newly formed, wholly-owned subsidiary of Dominion, Dominion Oklahoma Texas Exploration & Production, Inc. (DOTEPI). Immediately after the merger, Dominion contributed DOTEPI to the Company. The acquisition of DOTEPI doubled the Company's proved gas and oil reserves. DOTEPI is included in the Company's Exploration & Production operating segment.

In 2000, Dominion created a subsidiary service company, Dominion Resources Services, Inc. (Dominion Services), as required under the 1935 Act that serves Dominion's various subsidiaries. During 2000, the Company also operated a service company, Consolidated Natural Gas Service Company, Inc. (CNG Services). Effective January 1, 2001, Dominion combined the two service companies, and Dominion Services became the surviving service company.

The Company manages its daily operations through three primary operating segments: Delivery, Energy, and Exploration & Production. In addition, the Company also reports its corporate functions as a segment. Assets remain wholly-owned by the Company's legal subsidiaries. See Note 25.

The ***Delivery*** segment manages the Company's retail gas distribution subsidiaries, Dominion East Ohio, Dominion Peoples and Dominion Hope.

The ***Energy*** segment manages the Company's gas transmission pipeline, storage and by-product operations, gas production operations of Dominion Transmission and the activities of Dominion Field Services, Dominion Retail, Dominion Products and Services and Dominion Cove Point.

The ***Exploration & Production*** segment manages the Company's gas and oil exploration and production operations of Dominion E&P and DOTEPI and the investments held by CNG Main Pass Gas Gathering and CNG Oil Gathering.

In addition, the Company also reports the corporate functions as a segment. The ***Corporate and Other*** segment includes the activities of CNG International and other minor subsidiaries, costs of the Company's corporate functions and certain expenses which are not allocated to the operating segments.

The "Company" is used throughout this report and, depending on the context of its use, may represent any of the following: the legal entity, Consolidated Natural Gas Company, one of Consolidated Natural Gas Company's consolidated subsidiaries or the entirety of Consolidated Natural Gas Company and its consolidated subsidiaries.

Note 2. Significant Accounting Policies

General

The Company makes certain estimates and assumptions in preparing its Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles). These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses for the periods presented. Actual results may differ from those estimates.

The Consolidated Financial Statements represent the accounts of the Company and its subsidiaries, with intercompany transactions eliminated in consolidation. The Company follows the equity method of accounting for investments with less than a 50 percent interest in partnerships and corporate joint ventures when the Company is able to influence the financial and operating policies of the investee.

Certain amounts in the 2001 and 2000 Consolidated Financial Statements have been reclassified to conform to the 2002 presentation.

Use of Fair Value Measurements

The Company reports certain contracts and instruments at fair value in accordance with applicable generally accepted accounting principles. Fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, the Company must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis.

For options and contracts with option-like characteristics where pricing information is not available from external sources, the Company uses a modified Black-Scholes model and considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. For contracts with unique characteristics, the Company estimates fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. If pricing information is not available from external sources, judgment is required to develop the estimates of fair value. For individual contracts, the use of different assumptions could have a material effect on the contract's estimated fair value.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. See Note 6.

Purchased Gas—Deferred Costs

Where permitted by regulatory authorities, the differences between actual purchased gas expenses and the levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. See *Regulatory Assets and Liabilities* discussed below and in Note 14.

Income Taxes

Effective 2000, the Company files a consolidated federal income tax return and participates in an intercompany tax allocation agreement with Dominion and its subsidiaries. The Company's current income taxes are based on its taxable income, determined on a separate company basis. However, under the 1935 Act and the intercompany tax allocation agreement, the Company's cash payments to Dominion are reduced for a portion of income tax benefits realized by Dominion as a result of filing consolidated returns. Where permitted by regulatory authorities, the treatment of temporary differences can differ from the requirements of Statement of Financial Accounting Standards (SFAS) No. 109, *Accounting for Income Taxes*. Accordingly, a regulatory asset has been recognized if it is probable that future revenue will be provided for the payment of deferred tax liabilities. Deferred investment tax credits are being amortized over the service lives of the property giving rise to such credits.

Stock-based Compensation

Employees of the Company may receive stock-based awards, such as stock options and restricted stock, granted under Dominion-sponsored stock plans. The Company measures compensation cost for stock-based awards issued to its employees in accordance with Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Compensation expense is measured as the difference between fair market value of Dominion common stock and the exercise price of the underlying award on the date when both the price and number of shares the recipient is entitled to receive are known, generally the grant date. Compensation expense, if any, is recognized on a straight-line basis over the stated vesting period of the award. Compensation expense associated with these awards was not material in 2002, 2001 and 2000. The pro forma impact on net income, had the Company measured compensation expense based on the fair value of the options on the date of grant, would not have been material for 2002, 2001 and 2000.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until actually presented for payment. At December 31, 2002 and 2001, accounts payable included the net effect of checks outstanding but not yet presented for payment of $34 million and $36 million, respectively. For purposes of the Consolidated Statements of Cash Flows, the Company considers cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with a remaining maturity of three months or less.

Margin Deposit Assets and Liabilities

Amounts reported as margin deposit assets represent funds held on deposit by various counterparties that resulted from the Company exceeding agreed-upon credit limits established by the counterparty. Amounts reported as margin deposit liabilities represent funds held by the Company that resulted from various counterparties exceeding agreed-upon credit limits established by the Company. These credit limits and the mechanism for calculating the amounts to be held on deposit are determined in the International Swap Dealers Association master agreements in place between the Company and the counterparties. As of December 31, 2002 and 2001, the Company had margin deposit assets of $52 million and $20 million, respectively. The Company had no margin deposit liabilities at December 31, 2002. Margin deposit liabilities were $88 million at December 31, 2001.

Property, Plant and Equipment

Property, plant and equipment, including additions and replacements, is recorded at original cost, including labor, materials, other direct costs and capitalized interest. The costs of repairs and maintenance, including minor additions and replacements, are charged to expense as incurred. In 2002, 2001 and 2000, the Company capitalized interest costs of $70 million, $22 million and $10 million, respectively.

The depreciable cost of gas utility and transmission property retired and the related cost of removal, less salvage, are charged to accumulated depreciation at retirement. The Company records gains and losses upon retirement of nonregulated property based on the difference between proceeds received, if any, and the property's undepreciated basis at the retirement date.

Depreciation of property, plant and equipment is computed on the straight-line method based on projected service lives or in the case of gas and oil producing properties, the unit-of-production method. The Company's annual depreciation rates on property, plant and equipment for 2002, 2001 and 2000 are as follows: transmission—2.38 percent, 2.41 percent and 2.46 percent, respectively; distribution—2.42 percent, 2.43 percent and 2.51 percent, respectively; storage—2.47 percent, 2.57 percent and 2.61 percent, respectively; gas gathering and processing—2.31 percent, 2.19 percent and 2.62 percent, respectively; and general—6.50 percent, 7.08 percent and 4.37 percent, respectively.

The Company follows the full cost method of accounting for gas and oil exploration and production activities prescribed by the Securities and Exchange Commission (SEC). Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized. The full cost method limits these capitalized amounts to no more than the present value of estimated future net revenue to be derived from the production of proved gas and oil reserves as determined under a method established by the SEC (the ceiling test). If net capitalized costs exceed the ceiling test at the end of any quarterly period, then a permanent write-down of the assets must be recognized in that period. The ceiling test is performed separately for each cost center, with cost centers established on a country-by-country basis. As currently permitted by the SEC, the Company uses hedge-adjusted period-end prices to calculate the present value of estimated future net revenue. Such prices are used for the portion of anticipated production from proved reserves that is hedged by qualifying cash flow hedges. As of December 31, 2002, the use of period-end market prices rather than hedge-adjusted prices, as otherwise required by the full cost method, would not have resulted in an impairment charge. Due to the volatility of gas and oil prices, it is reasonably possible that for some periods, the Company may satisfy the ceiling test using hedge-adjusted prices, whereas the use of period-end market prices without the effects of hedging could have resulted in an impairment charge.

Depreciation of gas and oil producing properties is computed using the unit-of-production method. Under the full cost method of accounting, amortization is also accrued on estimated future costs to be incurred in developing proved gas and oil reserves and on estimated dismantlement and abandonment costs, net of projected salvage values. The costs of investments in unproved properties are initially excluded from the depreciable base. Until the properties are evaluated, a ratable portion of the capitalized costs is periodically reclassified to the depreciable base, determined on a property by property basis, over terms of underlying leases. Once a property has been evaluated, any remaining capitalized costs are then transferred to the depreciable base.

For a discussion of the Company's implementation of a change in the accounting for estimated dismantlement and abandonment costs in its gas and oil exploration and production activities, see *Asset Retirement Obligations* in Note 4.

Impairment of Long-Lived and Intangible Assets

The Company performs an evaluation for impairment whenever events or changes in circumstances indicate that the carrying amount of long-lived assets or intangible assets with finite lives may not be recoverable. These assets are written down to fair value if the sum of the expected future undiscounted cash flows is less than the carrying amounts.

Derivative Instruments

The Company uses derivative instruments such as forwards, futures, swaps and options to manage the commodity and financial market risks of its business operations. Derivative instruments are generally recognized on the Consolidated Balance Sheet at fair value. See Note 11 for further discussion of the Company's use of derivative instruments, including its risk management policy, its accounting policy for derivatives under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and the results of its hedging activities for the years ended December 31, 2002 and 2001.

Prior to January 1, 2001, the Company considered derivative instruments to be effective hedges when the item being hedged and the underlying financial instrument or commodity contract showed strong historical correlation. The Company used deferral accounting to account for futures, forwards and other derivative instruments that were designated as hedges. Under this method, realized gains and losses (including the payment of any premium) related to effective hedges of existing assets and liabilities were recognized in earnings in conjunction with the designated asset or liability. Gains and losses related to effective hedges of firm commitments and anticipated transactions were included in the measurement of the subsequent transaction.

Goodwill, Net

Prior to the adoption of SFAS No. 142, *Goodwill and Other Intangible Assets*, on January 1, 2002, goodwill arising from acquisitions completed before July 1, 2001 was amortized on a straight-line basis over periods up to 40 years. In accordance with SFAS No. 142, the Company did not amortize goodwill arising from acquisitions initiated after June 30, 2001 and ceased amortization of all goodwill upon adoption of the standard. The Company evaluates goodwill for impairment at least on an annual basis or when an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. See Note 13 for further discussion of the adoption of SFAS No. 142. See Note 5 for a discussion of the Company's recent significant acquisitions.

Regulatory Assets and Liabilities

Methods of allocating costs to accounting periods for operations subject to federal or state cost-of-service rate regulation may differ from accounting methods generally applied by nonregulated companies. The economic effects of allocations prescribed by regulatory authorities for ratemaking purposes must be considered in the application of generally accepted accounting principles. See Note 14 for additional information on *Regulatory Assets and Liabilities*.

Amortization of Debt Issuance Costs

The Company defers and amortizes debt issuance costs and debt premiums or discounts over the lives of the respective debt issues. As permitted by regulatory authorities, gains or losses resulting from the refinancing of debt allocable to utility operations subject to cost-based rate regulation have also been deferred and amortized over the lives of the new issues.

Note 3. Accounting Change for Pension Costs

Effective January 1, 2000 and in connection with Dominion's acquisition of the Company, Dominion and its subsidiaries, including the Company, adopted a new company-wide method of calculating the market-related value of pension plan assets used to determine the expected return on pension plan assets, a component of net periodic pension cost. The Company believes the new method enhances the predictability of the expected return on pension plan assets; provides consistent treatment of all investment gains and losses; and results in calculated market-related pension plan asset values that are closer to market value than the values calculated under the pre-acquisition methods used by Dominion and the Company.

The $31 million cumulative effect of the change on prior years (net of income taxes of $11 million) was included in income for the year ended December 31, 2000. The effect of the change on 2000 was to increase income before cumulative effect of a change in accounting principle by $10 million and net income by $41 million.

Note 4. Recently Issued Accounting Standards

Asset Retirement Obligations

In 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, which provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. The Company adopted the standard effective January 1, 2003.

The Company has identified certain asset retirement obligations that are subject to the standard. These obligations are primarily associated with the abandonment of certain natural gas pipelines, the removal of certain facilities, and the dismantlement and restoration activities for its gas and oil wells and platforms.

Under SFAS No. 143, asset retirement obligations will be recognized at fair value, as incurred, and capitalized as part of the cost of the related tangible long-lived assets. Under the present value approach used to estimate the fair value of asset retirement obligations, accretion of the liabilities due to the passage of time will be recognized as an operating expense. Prior to the adoption of SFAS No. 143, the Company's accounting and reporting practices for future dismantlement and restoration activities for its gas and oil wells and platforms recognized such costs as a component of depreciation, with recognized amounts included in accumulated depreciation.

On January 1, 2003, the Company implemented SFAS No. 143 and recognized an after-tax loss of $5 million, representing the cumulative effect of a change in accounting principle. Under the Company's accounting policy prior to the adoption of SFAS No. 143, $84 million had previously been accrued for future asset removal costs, primarily related to future dismantlement and restoration activities associated with the Company's gas and oil wells platforms. Such amounts are included in the accumulated provision for depreciation, depletion and amortization as of December 31, 2002. With the adoption of SFAS No. 143, the Company calculated its asset retirement obligations to be $198 million. In recording the cumulative effect of the accounting change, the Company recognized the increase attributable to the re-measurement of asset retirement obligations and reclassified the previously recorded amount from the accumulated provision for depreciation, depletion and amortization to other non-current liabilities. The cumulative effect of the accounting change also reflected a $109 million increase in property, plant and equipment for capitalized asset retirement costs and a $3 million increase in the accumulated provision for depreciation, depletion and amortization, representing the depreciation of such costs through December 31, 2002.

In accordance with SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, the Company will continue its practice of accruing for future costs of removal for its cost-of-service rate-regulated gas utility assets, even if no legal obligation to perform such activities exists.

At December 31, 2002, the Company's accumulated depreciation, depletion and amortization included $221 million, representing the estimated future cost of such removal activities.

Accounting for Guarantees

In November 2002, the FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others—An Interpretation of FASB Statements No. 5, 57 and 107*. Under the Interpretation, issuers of certain types of guarantees must recognize a liability based on the fair value of the guarantee issued, even when the likelihood of making payments is remote. In addition, the Interpretation requires increased disclosures for specific types of guarantees.

The Interpretation's initial recognition requirements apply only to guarantees issued or modified after December 31, 2002. The Company does not anticipate any material impact on its future results of operations or financial condition as a result of recording newly issued or modified guarantees at fair value. The Interpretation's disclosure requirements are effective for financial statements ending after December 15, 2002. See Note 21.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities*, which addresses consolidation by business enterprises of entities that are not controllable through voting interests or in which the equity investors do not bear the residual economic risks and rewards. These entities have been commonly referred to as "special purpose entities." The underlying principle behind the new Interpretation is that if a business enterprise has the majority financial interest in an entity, defined in the guidance as a variable interest entity, the assets, liabilities, and results of the activities of the variable interest entity should be included in consolidated financial statements with those of the business enterprise. The Interpretation explains how to identify variable interest entities and how an enterprise should assess its interest in an entity to decide whether to consolidate that entity. The Company will apply the provisions of Interpretation No. 46 prospectively for all variable interest entities created after January 31, 2003. For variable interest entities created before January 31, 2003, the Company will be required to consolidate all entities in which it was deemed to be the primary beneficiary beginning July 1, 2003. The Company does not anticipate that the adoption of Interpretation No. 46 will have a material impact on its results of operations or financial condition.

SFAS No. 133 Guidance

In connection with the January 2003 Emerging Issues Task Force meeting, FASB was requested to reconsider an interpretation of SFAS No. 133. The interpretation, which is contained in the Derivatives Implementation Group's C11 guidance, relates to contracts with pricing terms that include broad market indices. In particular, that guidance discusses whether the pricing in a contract that contains broad market indices (e.g., consumer price index) could qualify as a normal purchase or sale and therefore not be subject to fair value accounting. The Company has one electric power sales contract that is subject to the guidance addressed in the request for reconsideration. The Company does not expect the effect of implementing any change, that would ultimately be required as a result of the guidance being clarified, to be material to its results of operations or financial position.

Note 5. Merger and Acquisitions

Acquisition of Dominion Cove Point

In 2002, the Company acquired 100 percent ownership of Dominion Cove Point, a cost-based rate-regulated entity, from a subsidiary of The Williams Companies for $225 million in cash. The Company recorded $75 million of goodwill, representing the excess of the purchase price over the regulatory basis of Dominion Cove Point's assets acquired and liabilities assumed. Dominion Cove Point's assets include a liquefied natural gas import facility located near Baltimore, Maryland that is under reconstruction, a liquefied natural gas storage facility and an approximately 85-mile natural gas pipeline. The Company expects Dominion Cove Point to become fully operational in 2003. The Company incurred $33 million of additional development costs during 2002 and expects to incur $84 million of costs in 2003. All the goodwill arising from the acquisition has been allocated to the Energy segment for purposes of impairment testing under SFAS No. 142.

Acquisition of Louis Dreyfus

In 2001, Dominion acquired all of the outstanding shares of common stock of Louis Dreyfus, a natural gas and oil exploration and production company headquartered in Oklahoma City, Oklahoma. Dominion acquired Louis Dreyfus by merging it into a newly formed, wholly-owned subsidiary of Dominion, DOTEPI. Immediately after the merger, Dominion contributed DOTEPI to the Company.

The aggregate purchase price was $1.8 billion, which consisted of approximately 14 million shares of Dominion common stock valued at $881 million, $902 million in cash and employee stock options with a fair value on the date of grant of approximately $13 million. The Company initially recorded $519 million of goodwill, representing the excess of purchase price over amounts allocated to Louis Dreyfus' assets acquired and liabilities assumed. The purchase price allocation was completed during the first quarter of 2002 upon receipt of information from outside specialists, increasing liabilities and goodwill each by $24 million.

All of the goodwill arising from the acquisition has been allocated to the Exploration & Production segment for purposes of impairment testing under SFAS No. 142. In accordance with SFAS No. 142, no goodwill amortization was recorded related to the acquisition. See Note 13 for further discussion.

Merger with Dominion

On January 28, 2000, Dominion acquired all of the outstanding shares of the Company's common stock for $6.4 billion, consisting of approximately 87 million shares of Dominion common stock valued at $3.5 billion and approximately $2.9 billion in cash. Dominion completed the acquisition by merging the Company into a new subsidiary. Dominion changed the name of the new subsidiary to Consolidated Natural Gas Company at the time of the merger. Due to the Company's outstanding publicly traded indebtedness, goodwill and purchase accounting adjustments were not pushed down to the Company by Dominion.

Note 6. Operating Revenue

The Company's operating revenue consists of the following:

	Year Ended December 31,		
	2002	2001	2000
		(Millions)	
Regulated gas sales	$ 876	$1,409	$1,719
Nonregulated gas sales	883	1,055	746
Gas transportation and storage	737	718	551
Gas and oil production	990	706	532
Other	414	349	467
Total operating revenue	$3,900	$4,237	$4,015

The primary types of sales and service activities reported as operating revenue include:

Regulated gas sales consists primarily of state-regulated retail natural gas sales and related distribution services. The Company's customer accounts receivable at December 31, 2002 and 2001 included $103 million and $126 million, respectively, of accrued unbilled revenue based on estimated amounts of natural gas delivered but not yet billed to its utility customers. The Company estimates unbilled utility revenue based on weather factors, historical usage and applicable customer rates.

Nonregulated gas sales consists primarily of sales of natural gas at market-based rates, brokered gas sales and other gas marketing activities. Natural gas sold includes gas produced by the Company as well as gas purchased from others.

Gas transportation and storage consists primarily of federally regulated sales of transmission, distribution and storage services. Also, included are state-regulated gas distribution charges charged to retail distribution service customers opting for alternate suppliers.

Gas and oil production consists primarily of sales of natural gas, oil and condensate produced by the Company. Gas and oil production revenue is reported net of royalties.

Other revenue consists primarily of miscellaneous service revenue from gas distribution operations; brokered oil and other extracted products; gas and oil processing; gas transmission pipeline capacity release and nonregulated sales of electricity.

Note 7. Restructuring and Other Merger-Related Activities

2001 Restructuring Costs

In the fourth quarter of 2001, after fully integrating the Company into Dominion's existing organization and operations, management initiated a focused review of Dominion's combined operations and developed a plan of reorganization. As a result, the Company recognized $45 million of restructuring costs which included employee severance and related benefits and the abandonment of leased office space no longer needed.

The Company recorded $34 million in total severance and related costs, including $21 million billed to the Company by Dominion Services. Under the 2001 restructuring plan, the Company identified approximately 141 salaried positions to be eliminated and recorded $13 million in employee severance-related costs. Severance payments were based on the individual's base salary and years-of-service at the time of termination. In 2002, the Company recorded a $2 million credit in Restructuring and Other Merger-Related Costs in the Consolidated Statements of Income, reflecting a $4 million reduction in the Company's liability for severance and related costs, offset in part by a $2 million adjustment associated with severance and related costs billed to the Company by Dominion Services. With 100 positions actually being eliminated under the Company's plan, the $4 million adjustment reflected a reduction in the number of employee positions being eliminated and a reduction for differences between actual and estimated base salaries and years-of-service for those employees actually terminated under the plan.

Restructuring and related costs for the year ended December 31, 2001 were as follows:

	(Millions)
Severance and related costs	$13
Severance and related costs—Dominion Services[1]	21
Other[2]	11
Total restructuring costs	$45

[1] Dominion Services, a Dominion subsidiary service company under the 1935 Act, provides certain services to Dominion's operating subsidiaries. Accordingly, charges are allocated and billed among the operating subsidiaries in accordance with predefined service agreements. See Note 24.

[2] Includes charges for abandonment of leased office space and related costs by the Company and Dominion Services.

The change in the liabilities for severance and related costs and lease abandonment costs during 2002 is presented below:

	Severance Liability	Lease Liability
	(Millions)	
Balance at December 31, 2001	$13	$ 7
Amounts paid	(5)	(1)
Revision of estimate	(4)	—
Balance at December 31, 2002	$ 4	$ 6

2000 Restructuring and Other Merger-Related Costs

In 2000, following the merger with Dominion, Dominion and its subsidiaries implemented a plan to restructure the operations of the combined companies. The restructuring plan included an involuntary severance program, a voluntary early retirement program (ERP) and a transition plan to implement operational changes to provide efficiencies, including the consolidation of post-merger operations and the integration of information technology systems. Through December 31, 2001, 429 positions had been eliminated, and approximately $26 million of severance benefits had been paid. Severance payments were based on the individual's base salary and years-of-service at the time of termination. In addition, during 2001, the Company adjusted the severance liability by approximately $2 million, reflecting a revision in severance benefits payable for differences between the estimates used in the plan and the actual base salaries and years-of-service for those employees terminated under the plan. During 2000, approximately 450 employees elected to participate in the ERP, resulting in an expense approximating $62 million. This expense was offset, in part, by curtailment gains of $26 million attributable to reductions in expected future years of service as a result of ERP participation and involuntary employee terminations. Some of the ERP participants also received benefits under the involuntary severance package; benefits under the involuntary severance package were subject to reduction as a result of coordination with the additional retirement plan benefits provided by the ERP.

For the year ended December 31, 2000, the Company recorded $270 million of restructuring and other merger-related costs, as follows:

	(Millions)
Commodity contract losses	$ 55
Settlement of certain employment contracts	47
ERP (see Note 20)	36
Information technology-related costs	35
Severance liability accrued	31
Seismic licensing agreements	26
Transaction fees	10
Lease termination or modification	8
Other	22
Total	$270

At December 31, 2001, $1 million of severance and related benefit costs accrued under the plan had not yet been paid; such amounts were paid during 2002.

During the first quarter of 2000, Dominion created an enterprise risk management group with responsibility for managing Dominion's aggregate energy portfolio, including the related commodity price risk, across its consolidated operations. In connection with this change in risk management strategy, management evaluated the Company's hedging strategy in relation to Dominion's combined operations and designated its January 28, 2000 portfolio of derivative contracts as held for purposes other than hedging for accounting purposes. This action required a change to mark-to-market accounting and resulted in $55 million of losses recognized in the first quarter of 2000. See Note 11.

In addition, the Company incurred the following costs: settlement of certain employment contracts; payments under seismic licensing agreements in gas and oil operations; information technology-related costs, including excess amortization expense attributable to shortening the useful lives of capitalized software being impacted by systems integration and related conversion costs; and lease termination and restructuring costs as a result of the consolidation of operations.

Sale of Virginia Natural Gas (VNG)

In October 2000, the Company completed the sale of VNG to AGL Resources Inc. (AGL). Cash proceeds from the sale amounted to $532 million.

In connection with the sale of VNG, the Company transferred the pension and postretirement medical benefit liabilities relating to VNG's employees to AGL, together with the related plan assets. As a result, the Company recognized curtailment and settlement gains of $26 million. The total gain recognized on the sale of VNG, including the curtailment and settlement gains, amounted to $163 million ($98 million after taxes).

Note 8. International Investments

CNG International was engaged in energy-related activities outside of the United States, primarily through equity investments in companies located in Australia and Argentina. In 2000, the Company's management committed to a plan to dispose of the entire operations of CNG International consistent with its strategy to focus on its core business. In July 2000, the Company sold its Argentine assets for $145 million in cash. At December 31, 2002 and 2001, CNG International's assets held for sale consisted primarily of equity method investments of $76 million and $61 million, respectively, and property, plant and equipment of $55 million and $15 million, respectively.

The Company remains committed to its plan of disposal and is actively engaged to locate buyers for the remaining CNG International assets.

Australian Investments

CNG International owns, through intermediate subsidiaries, a one-third interest in certain Australian long distance natural gas pipeline systems, including the 925-mile Dampier-to-Bunbury Natural Gas Pipeline (DBNGP) in Western Australia. Under an equity contribution agreement associated with a debt financing, the Company is contractually obligated to make equity contributions of $100 million, if required, to ensure repayment of the debt that matures in October 2003.

In June 2001, regulators in Western Australia issued a draft rate decision for the DBNGP that provided lower than expected rates. The decision was appealed to the Western Australia Supreme Court which ruled in favor of the DBNGP on certain issues. As a result, the rate case was returned to the regulators for reconsideration. The regulators' final rate decision is expected sometime in 2003. In addition, the DBNGP has debt of approximately AUD$1.7 billion (US$960 million) that is scheduled to mature in September 2003.

If an unfavorable final rate decision is issued, the Company's equity investment could be impaired. The recognition of impairment, if ultimately required, would not result in a material impact on the Company's results of operations or its financial position. However, a sale of the Company's investment is expected to require a $100 million payment under the equity contribution agreement discussed above. Completing a sale of the Company's investment in 2003 could be dependent on eliminating the uncertainties represented by the pending rate decision.

2000 Impairment Losses

In 2000, the Company recognized losses related to CNG International's Argentine and Australian investments of $152 million ($99 million after taxes). In anticipation of the sale of the Argentine assets, the Company adjusted the carrying amount of its investment by recognizing an impairment loss of $17 million ($11 million after taxes). In addition, in connection with the Company's decision to end its involvement with international activities, the Company evaluated its Australian investments for impairment. As a result, the Company recognized an impairment loss of $35 million ($23 million after taxes) and a charge of $100 million ($61 million after taxes), reflecting its obligation to fund the equity contribution expected to be required under the agreement discussed above.

Note 9. Income Taxes

Details of income tax expense were as follows:

	Year Ended December 31,		
	2002	2001	2000
		(Millions)	
Current:			
Federal	$ (74)	$105	$108
State	(7)	22	12
Total current	(81)	127	120
Deferred:			
Federal	373	74	22
State	22	—	7
Total deferred	395	74	29
Amortization of deferred investment tax credits—net	(2)	(2)	(2)
Total income tax expense	$312	$199	$147

Total statutory U.S. federal income rate reconciles to the effective income tax rates as follows:

	Year Ended December 31,		
	2002	2001	2000
U.S statutory rate	35.0%	35.0%	35.0%
Increases (reductions) resulting from:			
Amortization of investment tax credits	(0.2)	(0.3)	(0.5)
Nonconventional fuel credit	(1.0)	(2.1)	(2.8)
State taxes, net of federal benefit	1.0	2.5	3.3
SFAS No. 71 flow through item: employee pension and other benefits	(1.2)	(2.0)	(2.2)
SFAS No. 71 flow through item: gain on sale of assets	—	—	1.9
Nondeductible change of control payments	—	—	2.2
Prior year tax adjustment	—	—	2.5
Other, net	(0.8)	(0.2)	1.4
	(2.2)	(2.1)	5.8
Effective tax rate	32.8%	32.9%	40.8%

Deferred income taxes reflect the net effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

The Company's net deferred income taxes consist of the following:

	At December 31,	
	2002	2001
	(Millions)	
Deferred income tax assets:		
Other comprehensive income	$ 152	$ —
Gas storage inventory encroachment and other	41	38
Partnership basis differences	—	17
Uncollectible accounts	4	13
Deferred investment tax credits	6	8
Other	45	31
Total deferred income tax assets	248	107
Deferred income tax liabilities:		
Depreciation method and plant basis differences	485	446
Exploration and intangible drilling costs	662	469
Geological, geophysical and other exploration differences	389	255
Postretirement and pension benefits	226	191
Unrecovered gas costs and supplier refunds	83	119
Other comprehensive income	—	81
Other	61	5
Total deferred income tax liabilities	1,906	1,566
Total net deferred income tax liabilities[1]	$1,658	$1,459

[1] For 2002, amount includes $10 million of current deferred tax liabilities reported in Other Current Liabilities.

At December 31, 2002, the Company had U.S. federal net operating loss carryforwards of $47 million. These carryforwards are expected to be fully utilized between 2003 and 2007. These amounts resulted from the acquisition of subsidiaries.

Note 10. Inventories

At December 31, 2002 and 2001, stored gas inventory used in local gas distribution operations was valued at $52 million and $84 million, respectively, under the last-in-first-out (LIFO) method. Based on the average price of gas purchased during 2002, the current cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by approximately $163 million. At December 31, 2002 and 2001, the stored gas inventory of certain nonregulated gas operations of the Company was valued at $34 million and $38 million, respectively, using the weighted-average cost method.

A portion of gas in underground storage used as a pressure base and for operational balancing was included in Property, Plant and Equipment in the amount of $124 million at December 31, 2002 and 2001. Property, Plant and Equipment also reflected a reduction for volumes temporarily withdrawn from storage and valued at replacement costs of $53 million and $25 million as of December 31, 2002 and 2001, respectively.

Materials and supplies inventories are valued using primarily the weighted-average cost method.

Note 11. Derivative Instruments and Hedge Accounting

Adoption of SFAS No. 133

The Company adopted SFAS No. 133 on January 1, 2001 and recorded an after-tax loss of $14 million (net of income taxes of $8 million), representing the cumulative effect of adopting SFAS No. 133 in its Consolidated Statements of Income. The Company also recorded a net after-tax charge to Accumulated Other Comprehensive Income (AOCI) of $105 million, net of taxes of $57 million.

Risk Management Policy

The Company uses derivative instruments to manage the commodity and financial market risks of its business operations. The Company manages the price risk associated with purchases and sales of natural gas and oil by utilizing derivative instruments including futures, forwards, swaps and options. The Company manages its interest rate risk exposure, in part, by entering into interest rate swap transactions.

The Company has operating procedures in place that are administered by experienced management to help ensure that proper internal controls are maintained regarding the use of derivative instruments. In addition, Dominion has established an independent function to monitor compliance with the risk management policies of all subsidiaries.

The Company designates a substantial portion of its derivative instruments as fair value or cash flow hedges for accounting purposes. A significant portion of the Company's hedge strategies represents cash flow hedges of the variable price risk associated with purchases and sales of natural gas, oil and other commodities, using derivative instruments discussed in the preceding paragraphs. The Company also engages in fair value hedges by utilizing natural gas swaps, futures and options to mitigate the fixed-price exposure inherent in its firm commodity commitments. In addition, the Company has designated interest rate swaps as fair value and cash flow hedges to manage its exposure to fixed interest rates on certain long-term debt. Certain of the Company's derivatives are not designated as hedges for accounting purposes. However, management believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices.

Accounting Policy

Under SFAS No. 133, derivatives are recognized on the Consolidated Balance Sheets at fair value, unless an exception is available under the standard. Certain qualifying derivative contracts have been designated as normal purchases or normal sales contracts. These contracts are not reported at fair value, as otherwise required by SFAS No. 133.

Commodity contracts representing unrealized gain positions are reported as derivative assets; commodity contracts representing unrealized losses are reported as derivative liabilities. In addition, purchased options and options sold are reported as derivative assets and derivative liabilities, respectively, at estimated market value until exercise or expiration.

For all derivatives designated as hedges, the Company formally documents the relationship between the hedging instrument and the hedged item, as well as the risk management objective and strategy for the use of the hedging instrument. The Company assesses whether the hedge relationship between the derivative and the hedged item is highly effective in offsetting changes in fair value or cash flows both at the inception of the hedge and on an ongoing basis. Any change in fair value of the derivative that is not effective in offsetting changes in the fair value of the hedged item is recognized currently in earnings. The Company discontinues hedge accounting prospectively for derivatives that have ceased to be highly effective hedges.

For fair value hedge transactions in which the Company is hedging changes in the fair value of an asset, liability or firm commitment, changes in the fair value of the derivative will generally be offset in the Consolidated Statements of Income by changes in the hedged item's fair value. For cash flow hedge transactions in which the Company is hedging the variability of cash flows related to a variable-priced asset, liability, commitment or forecasted transaction, changes in the fair value of the derivative are reported in AOCI. Derivative gains and losses reported in AOCI are reclassified to earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portions of the change in fair value of derivatives and the change in fair value of derivatives not designated as hedges for accounting purposes are recognized in current-period earnings. For options designated either as fair value or cash flow hedges, changes in the time value are excluded from the measurement of hedge effectiveness and are, therefore, recorded in earnings.

Gains and losses on derivatives designated as hedges, when recognized, are included in Operating Revenue, Operating Expenses or Interest and Related Charges in the Consolidated Statements of Income. Specific line item classification is determined based on the nature of the risk underlying individual hedge strategies. Changes in the fair value of derivatives not designated as hedges, and the portion of hedging derivatives excluded from the measurement of effectiveness are included in Other Operations and Maintenance Expense in the Consolidated Statements of Income. Cash flows resulting from the settlement of derivatives used as hedging instruments are included in net cash from operating activities in the Consolidated Statements of Cash Flows.

Derivatives and Hedge Accounting Results

In the Consolidated Statements of Income, the Company recognized pre-tax gains (losses) related to hedge ineffectiveness and changes in time value of options excluded from the measurement of hedge effectiveness, as follows:

	2002	2001
	(Millions)	
Ineffectiveness:		
Fair value hedges	$—	$ 1
Cash flow hedges	(9)	—
Total ineffectiveness	$ (9)	$ 1
Change in options' time value:		
Fair value hedges	$ (1)	$—
Cash flow hedges	—	(37)
Total change in options' time value	$ (1)	$ (37)

The following table presents selected information related to cash flow hedges included in AOCI in the Consolidated Balance Sheet at December 31, 2002:

	Accumulated Other Comprehensive Income (Loss) After-Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months	Maximum Term
	(Millions)		
Commodities	$(296)	$(132)	62 months
Interest Rate	(1)	—	63 months
Total	$(297)	$(132)	

The actual amounts that will be reclassified to earnings in 2003 will vary from the expected amounts presented above as a result of changes in market prices. The effect of amounts being reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies.

In addition, $83 million of unrealized gains related to certain contracts designated as hedging instruments were reclassified from AOCI to earnings in December 2001. This reclassification was required in relation to the Company's recognition of an impairment of its gas and oil producing properties at December 31, 2001, due primarily to the decline in gas wellhead prices as of that date. See Note 12 for further discussion.

Enron Bankruptcy

Based on management's evaluation of the estimated collectibility of amounts due from Enron Corp. and certain of its subsidiaries (Enron) and the valuation of Enron-related commodity contracts, the Company recorded a pre-tax charge to earnings of approximately $108 million in the fourth quarter of 2001. This charge primarily represented the impaired fair value of natural gas forward and swap contracts with Enron. Management continues to believe that this charge substantially eliminates any further Enron-related earnings exposure.

During 2002, the Company terminated all outstanding and open positions with Enron. The Company has submitted a claim in the Enron bankruptcy case for the value of such contracts, measured at the effective dates of contract termination. Various contingencies, including developments in the Enron bankruptcy proceedings, may affect the Company's ultimate exposure to Enron.

Concurrent with the December 2, 2001 Enron bankruptcy filing, the Company's Enron derivatives designated as cash flow hedges of anticipated sales of natural gas no longer qualified for hedge accounting and, accordingly, were de-designated from their hedging relationships for accounting purposes.

Note 12. Property, Plant and Equipment

Property, plant and equipment consists of the following:

	At December 31,	
	2002	2001
	(Millions)	
Utility:		
Transmission	$ 1,685	$ 1,600
Distribution	1,825	1,736
Storage	781	755
Gas gathering and processing	341	285
General	183	221
Plant under construction	193	47
Total utility	5,008	4,644
Nonutility:		
Exploration and production:		
Proved	7,154	6,022
Unproved	1,775	1,614
Other	182	137
Total nonutility	9,111	7,773
Total property, plant and equipment	$14,119	$12,417

Costs of unproved properties capitalized under the full cost method of accounting that were excluded from amortization at December 31, 2002, and the years in which the excluded costs were incurred, follow:

	At December 31, 2002	Incurred in Years Ended December 31,			
		2002	2001	2000	Prior
		(Millions)			
Property acquisition costs	$ 861	$ 99	$735	$10	$17
Exploration costs	138	59	42	25	12
Capitalized interest	83	63	18	2	—
Total	$1,082	$221	$795	$37	$29

Amortization rates for capitalized costs under the full cost method of accounting for the Company's United States and Canadian gas and oil exploration and production activities were as follows:

	Year Ended December 31,		
	2002	2001	2000
	(Per Mcf Equivalent)		
United States cost center	$1.24	$1.24	$1.31
Canadian cost center	$ —	$ —	$ .17

At December 31, 2001, the Company recognized an impairment of its gas and oil producing, due primarily to the decline in gas wellhead prices. The non-cash charge amounted to $83 million and reduced 2001 net income by $53 million. The effect of the impairment adjustment was offset in its entirety by the reclassification of certain deferred gains from AOCI to earnings. These deferred gains related to hedging contracts that were not considered in the calculation of the impairment charge. Since the deferred gains related to hedges of forecasted sales from the Company's producing properties, such amounts were reclassified from AOCI to earnings when impairment of the producing properties was recognized. As of December 31, 2002, the use of period-end market prices, rather than hedge-adjusted prices, as otherwise required by the full cost method, did not result in an impairment charge.

There were no significant properties under development, as defined by the SEC, excluded from amortization at December 31, 2002. As gas and oil reserves are proved through drilling or as properties are deemed to be impaired, excluded costs and any related reserves are transferred on an ongoing, well-by-well basis into the amortization calculation.

Note 13. Goodwill and Intangible Assets

In 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 142 prohibits the amortization of goodwill and intangible assets with indefinite useful lives. SFAS No. 142 also requires that these assets be reviewed for impairment at least annually. Intangible assets with finite lives will continue to be amortized over their estimated useful lives and will be reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable.

The Company adopted SFAS No. 142 on January 1, 2002, and completed its transitional and annual goodwill impairment tests during the second quarter of 2002, finding no instances of impairment.

The change in the carrying amount of goodwill during 2002 is presented below:

	Energy	Exploration & Production	Total
	(Millions)		
Balance at December 31, 2001	$—	$519	$519
Adjustment of Dominion Cove Point (see Note 5)	75	—	75
Louis Dreyfus purchase accounting adjustment (see Note 5)	—	24	24
Other	7	—	7
Balance at December 31, 2002	$82	$543	$625

All of the Company's intangible assets, other than goodwill, are subject to amortization. Amortization expense for intangible assets was $19 million, $19 million and $20 million for 2002, 2001 and 2000, respectively. There were no material acquisitions of intangible assets during 2002. The components of intangible assets at December 31, 2002 were as follows:

	Gross Carrying Amount	Accumulated Amortization
	(Millions)	
Software and software licenses	$181	$84
Other	18	11
Total	$199	$95

Annual amortization expense for intangible assets is estimated to be $18 million for 2003, $17 million for 2004, $16 million for 2005, $15 million for 2006 and $13 million for 2007.

Note 14. Regulatory Assets and Liabilities

The Company accounts for its regulated operations in accordance with SFAS No. 71. See Note 2. Regulatory assets represent probable future revenue associated with certain costs that will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are to be credited to customers through the ratemaking process. The

Company's regulatory assets and liabilities included the following:

	At December 31, 2002	At December 31, 2001
	(Millions)	
Regulatory assets:		
Unrecovered gas costs	$ 32	$ 9
Workforce reduction costs	6	7
Other postretirement benefits	39	38
Income taxes recoverable through future rates	156	129
Customer bad debts	56	80
Other	8	13
Regulatory assets, net	265	267
Total regulatory assets	$297	$276
Regulatory liabilities:		
Amounts payable to customers	$ 13	$ 91
Estimated rate contingencies and refunds	21	43
Total regulatory liabilities	$ 34	$134

The incurred costs underlying regulatory assets may represent past expenditures by the Company's rate regulated gas operations or may represent the recognition of liabilities that ultimately will be settled at some time in the future. At December 31, 2002, approximately $94 million of the Company's regulatory assets represented past expenditures on which it does not earn a return. These expenditures consist primarily of unrecovered gas costs and customer bad debts. Unrecovered gas costs are recovered within two years; recovery of customer bad debts is expected to be addressed in the next base rate case.

Where permitted by regulatory authorities, the differences between actual purchased gas expenses and the levels of recovery of such expenses in current rates are deferred and matched against recoveries in future rates.

Pending the expected recovery of costs recognized under SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, the Company's rate-regulated subsidiaries deferred the differences between SFAS No. 106 costs and amounts included in rates. The rate-regulated subsidiaries have obtained approval for recovery in rates from their respective regulatory commissions for the increased level of expense resulting from the adoption of SFAS No. 106.

Income taxes recoverable through future rates represent amounts to be collected from customers related to the recognition of additional deferred income taxes not previously recorded because of past ratemaking practices.

In 2001, the Public Utilities Commission of Ohio (Ohio Commission) authorized the deferral of costs associated with certain uncollectible customer accounts not contemplated by current rates. In many cases, these customers' balances were adversely impacted by the previous winter's unusually high gas prices and cold weather. The Company expects recovery of such costs, which will be included in Dominion East Ohio's next base rate case.

Note 15. Short-Term Debt and Credit Agreements

Joint Credit Facilities

In May 2002, Dominion, Virginia Electric and Power Company (Virginia Power), a wholly-owned subsidiary of Dominion, and the Company entered into two joint credit facilities that allowed aggregate borrowings of up to $2 billion. The facilities include a $1.25 billion 364-day revolving credit facility that terminates in May 2003 and a $750 million three-year revolving credit facility that terminates in May 2005. The 364-day facility includes an option to extend any borrowings for an additional period of one year to May 2004. These joint credit facilities are being used for working capital, as support for the combined commercial paper programs of Dominion, Virginia Power and the Company and other general corporate purposes. The three-year facility can also be used to support up to $200 million of letters of credit. The Company expects to renew the 364-day revolving credit facility prior to its maturity in May 2003.

At December 31, 2002, total outstanding commercial paper supported by the joint credit facilities was $1.2 billion, of which the Company's borrowings were $397 million, with a weighted-average interest rate of 1.76 percent. At December 31, 2001, total outstanding commercial paper supported by previous credit agreements was $1.9 billion, of which the Company's borrowings were $776 million, with a weighted-average interest rate of 2.95 percent.

At December 31, 2002, total outstanding letters of credit supported by the three-year facility were $106 million, of which $35 million was issued for the Company on behalf of its subsidiaries. There were no outstanding letters of credit at December 31, 2001.

Credit Facility

In August 2002, the Company entered into a $500 million 364-day revolving credit facility that terminates in August 2003. This credit facility is being used to support the issuance of commercial paper and letters of credit to provide collateral required by counterparties on derivative financial contracts used by the Company in its risk management strategies for its gas and oil production. At December 31, 2002, outstanding letters of credit under this facility totaled $500 million.

Note 16. Long-Term Debt

The Company's long-term debt consists of the following:

	2002 Weighted-Average Coupon[1]	At December 31, 2002	At December 31, 2001
		(Millions)	
Senior Notes:			
5.375% to 7.375%, due 2003 to 2027	6.475%	$3,150	$3,150
6.875%, due 2026[2]	—	150	150
Senior Subordinated Debt:			
9.25%, due 2004[3]	—	88	94
		3,388	3,394
Fair value hedge valuation[4]		63	38
Amount due within one year		(150)	—
Unamortized discount and premium, net		8	13
Total long-term debt		$3,309	$3,445

(1) Represents weighted-average coupon rate for debt outstanding as of December 31, 2002.

(2) At the exercised option of holders, the Company will be required on October 15, 2006 to purchase the senior notes due October 15, 2026 at 100 percent of the principal amount plus accrued interest.

(3) In 2002, the Company redeemed $6 million of its 9.25 percent senior subordinated notes due June 15, 2004 at a repurchase price of 101 percent of principal plus accrued interest. The redemption was required as a result of the exercise of options by holders of the notes under terms of the applicable indenture.

(4) Represents changes in fair value of certain fixed-rate long-term debt associated with fair value hedging relationships, as described in Note 11.

The scheduled principal payments of long-term debt at December 31, 2002 were as follows (in millions):

2003	2004	2005	2006	2007	Thereafter	Total
$150	$488	$150	$500	$200	$1,900	$3,388

The Company's short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2002, there were no events of default under the Company's covenants.

Note 17. Company Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust

In 2001, Dominion CNG Capital Trust I (Trust), a subsidiary trust of the Company, sold 8 million 7.8 percent trust preferred securities for $200 million, representing preferred beneficial interests and 97 percent beneficial ownership in the assets held by the Trust. In exchange for the $200 million realized from the sale of the trust preferred securities and $6 million of common securities that represent the remaining 3 percent beneficial ownership interest in the assets held by the Trust, the Company issued $206 million of its 2001 7.8 percent junior subordinated notes due October 31, 2041 (Junior Subordinated Notes). The Junior Subordinated Notes constitute 100 percent of the Trust's assets. The Trust must redeem the trust preferred securities when the Junior Subordinated Notes are repaid or if redeemed prior to maturity.

Distribution payments on the trust preferred securities are guaranteed by the Company, but only to the extent that the Trust has funds legally and immediately available to make distributions. The Trust's ability to pay amounts when they are due on the trust preferred securities is solely dependent upon the payment of amounts when they are due on the Junior Subordinated Notes. If the payment on the Junior Subordinated Notes is deferred, the Company may not make distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, the Company may not make any payments or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the Junior Subordinated Notes.

Note 18. Accumulated Other Comprehensive Income

Presented in the table below is a summary of accumulated other comprehensive income by component (amounts are presented net of tax):

	At December 31, 2002	At December 31, 2001
	(Millions)	
Net unrealized gains (losses) on derivatives	$(297)	$ 83
Net unrealized losses on investment securities	(1)	—
Minimum pension liability adjustment	—	(1)
Total accumulated other comprehensive income (loss)	$(298)	$ 82

Note 19. Dividend Restrictions

The 1935 Act and related regulations issued by the SEC impose restrictions on the transfer and receipt of funds by a registered holding company from its subsidiaries, including a general prohibition against loans or advances being made by the subsidiaries to benefit the registered holding company. Under the 1935 Act, registered holding companies and their subsidiaries may pay dividends only from retained earnings, unless the SEC specifically authorizes payments from other capital accounts. The Company received dividends from its subsidiaries of $345 million, $336 million and $188 million in 2002, 2001 and 2000, respectively. At December 31, 2002, the Company's consolidated subsidiaries had approximately $2.7 billion in capital accounts other than retained earnings, representing capital stock, additional paid-in capital and accumulated other comprehensive income. The Company had approximately $3.4 billion in capital accounts other than retained earnings at December 31, 2002. Generally, such amounts are not available for the payment of dividends by affected subsidiaries, or by the Company itself, without specific authorization by the SEC. In 2000, in response to a Dominion request, the SEC granted relief, authorizing payment of dividends by the Company from other capital accounts to Dominion in amounts up to $1.6 billion, representing the Company's retained earnings prior to Dominion's acquisition of the Company. Furthermore, the Company submitted a similar request to the SEC in 2002, seeking relief from this restriction in regard to DOTEPI, the subsidiary into which Louis Dreyfus was merged. The application requests relief up to approximately $303 million, representing Louis Dreyfus' retained earnings prior to the acquisition by Dominion.

At December 31, 2000, one of the Company's indentures relating to its long-term debt contained restrictions on dividend payments by the Company. As of that date, $19 million of the Company's consolidated retained earnings was free from such restrictions. In March 2001, the Company requested and obtained the consent of bondholders to amend the indenture to eliminate certain provisions of the indenture, including such dividend restrictions. In March 2001, the Company received an order from the SEC, approving the amendment of the indenture.

Certain agreements associated with the Company's joint credit facilities with Dominion and Virginia Power contain restrictions on the ratio of debt to total capitalization. These limitations did not restrict the Company's ability to pay dividends to Dominion or receive dividends from its subsidiaries at December 31, 2002.

See Note 17 for a description of potential restrictions on dividend payments by the Company in connection with the deferral of distribution payments on trust preferred securities.

Note 20. Employee Benefits Plans

The Company provides certain benefits to eligible active employees, retirees and qualifying dependents. Under the terms of its benefit plans, the Company reserves the right to change, modify or terminate the plans. From time to time in the past, benefits have changed, and some of these changes have reduced benefits.

In 2000 and 2001, the Company maintained qualified noncontributory defined benefit retirement plans covering substantially all employees. In 2002, the Company's pension plan for employees not represented by recognized bargaining units was merged with the Dominion pension plan, which provides these benefits to multiple Dominion subsidiaries. The Company recognized $80 million of net periodic pension credit in 2002 related to the merged plan. The Company still maintains qualified pension plans that cover employee groups represented by collective bargaining units. Retirement benefits payable under all plans are based primarily on years-of-service, age and compensation. The Company's contributions to the plans are determined in accordance with the provisions of the Employment Retirement Income Security Act of 1974. Prior to 2002, the Company's pension program also included nonqualified pension plans which provided payment of supplemental pension benefits to certain retirees. Beginning in 2001, participants of certain of the nonqualified pension plans became employees of Dominion Services. As a result of this change, all associated plan liabilities were transferred to Dominion, and the Company reported no net periodic benefit costs related to affected participants under these plans after 2000. However, to the extent such employees provided services to the Company after 2000, the Company recognized such costs as part of the support services provided by Dominion Services.

Effective January 1, 2001, CNG Services was merged into Dominion Services. Employees of CNG Services became employees of Dominion Services but continued to participate in the Company's pension and other postretirement benefit plans during 2001. See Note 1. In 2002, such employees became participants in plans sponsored by Dominion.

The Company participates in plans providing retiree health care and life insurance benefits with annual premiums based on several factors such as age, retirement date and years-of-service.

Following the January 28, 2000 merger, Dominion and its subsidiaries, including the Company, offered an ERP as part of a plan to restructure the operations of the combined companies. The ERP provided up to three additional years of age and three additional years of employee service for benefit formula purposes, subject to age and service maximums under the Company's postretirement medical and pension plans. Certain employees who satisfied minimum age and years-of-service requirements were eligible under the ERP. The effect of the ERP on the Company's pension plan and postretirement benefit expenses was $42 million and $20 million, respectively. These expenses were offset, in part, by curtailment gains of approximately $19 million and $7 million from pension plans and other postretirement benefit plans, respectively, attributable to reductions in expected future years-of-service as a result of ERP participation and involuntary employee terminations.

In addition, effective January 1, 2000, Dominion and its subsidiaries, including the Company, adopted a change in the method of calculating the market-related value of pension plan assets. The cumulative effect of this change on prior years was reported as a change in accounting principle. See Note 3.

The following tables summarize information for the Company's pension and other postretirement benefit plans, including the changes in the pension and other postretirement benefit plan obligations and plan assets for each of the years ended December 31, 2002 and 2001, and a statement of the plans' funded status as of December 31, 2002 and 2001:

	Pension Benefit Plans			Other Postretirement Benefit Plans		
	2002(1)	2002(2)	2001	2002(1)	2002(2)	2001
	(Millions)					
Change in benefit obligation:						
Actual benefit obligation—January 1	$2,068	$ 429	$1,006	$ 715	$ 280	$ 363
Acquisition of business	2	—	—	3	—	—
Transferred to parent company	—	—	(27)	—	—	—
Service cost	63	8	18	34	10	14
Interest cost	141	29	71	49	20	26
Plan amendments	1	11	4	(11)	(8)	18
Actuarial loss	78	7	42	49	35	32
Benefit payments	(102)	(31)	(77)	(37)	(21)	(33)
Expected benefit obligation—December 31	$2,251	$ 453	$1,037	$ 802	$ 316	$ 420
Change in plan assets:						
Fair value of plan assets—January 1	$2,311	$1,037	$2,286	$ 318	$ 128	$ 142
Actual return on plan assets	(206)	(34)	(46)	(26)	(5)	10
Employer contributions	95	—	1	33	28	49
Benefit payments	(102)	(31)	(78)	(12)	(20)	(23)
Fair value of plan assets—December 31	$2,098	$ 972	$2,163	$ 313	$ 131	$ 178
Funded status:						
Funded status—December 31	$ (153)	$ 519	$1,126	$(489)	$(185)	$(243)
Unrecognized net transition (asset) obligation	976	(5)	(22)	92	57	117
Unrecognized net actuarial (gain) loss	(10)	(51)	(508)	210	93	36
Unamortized prior service cost	(2)	14	6	11	(3)	10
Prepaid (accrued) benefit cost	$ 811	$ 477	$ 602	$(176)	$ (38)	$ (80)
Amounts recognized in the Consolidated Balance Sheets at December 31:						
Prepaid pension cost	$ 261	$ 477	$ 568	$ —	$ —	$ —
Accrued benefit liability	—	—	(8)	(38)	(38)	(74)
Accumulated other comprehensive income	—	—	2	—	—	—
Net amount recognized	$ 261	$ 477	$ 562	$ (38)	$ (38)	$ (74)

(1) Amounts represent Dominion's pension and other postretirement benefit plans, into which the Company's benefit plans for employees not represented by collective bargaining units were merged in 2002. The Dominion plans provide benefits to employees of multiple Dominion subsidiaries.

(2) Amounts represent benefit plans covering employees represented by recognized bargaining units of the Company's subsidiaries.

The components of the provision for net periodic benefit cost were as follows:

	Year Ended December 31,							
	Pension Benefit Plans				Other Postretirement Benefit Plans			
	2002[1]	2002[2]	2001	2000	2002[1]	2002[2]	2001	2000
	(Millions)							
Service cost	$ 63	$ 8	$ 18	$ 21	$ 34	$ 10	$ 14	$ 11
Interest cost	141	29	71	72	49	20	26	24
Expected return on assets	(241)	(107)	(211)	(193)	(26)	(8)	(8)	(7)
Prior service cost amortization	(1)	—	1	1	1	—	(1)	—
Actuarial gain	—	(16)	(43)	(44)	—	—	—	—
Transition obligation (asset) amortization	(3)	(5)	(9)	(8)	10	7	11	11
Amortization of unrecognized net loss	—	—	—	—	3	2	—	—
Special termination benefits	—	—	—	42	—	—	—	20
Curtailment gain	—	—	—	(19)	—	—	—	(7)
Curtailment and settlement gain—Sale of VNG	—	—	—	(26)	—	—	—	—
Special voluntary retirement programs	—	—	—	1	—	—	—	—
Net periodic benefit cost (credit)	$ (41)	$ (91)	$(173)	$(153)	$ 71	$ 31	$ 42	$ 52
Company's net periodic benefit cost (credit)[3]	$ (80)	$ (91)	$(161)	$(153)	$ 15	$ 31	$ 40	$ 52

(1) Amounts represent Dominion's pension and other postretirement benefit plans, into which the Company's benefit plans for employees not represented by collective bargaining units were merged in 2002. The Dominion plans provide benefits to employees of multiple Dominion subsidiaries.
(2) Amounts represent benefit plans covering employees represented by recognized bargaining units of the Company's subsidiaries.
(3) Amounts represent all benefit plans in which the Company participates, including benefit plans covering multiple Dominion subsidiaries for 2002 and 2001.

Significant assumptions used in determining net periodic benefit cost, the projected benefit obligation and postretirement benefit obligations were:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets[1]	9.50%	9.50%	6.50%	5.70%
Rate of increase for compensation:				
Non-union		5.00%		5.00%
Union	4.00%	4.00%	4.00%	4.00%
Medical cost trend rate[2]			9.00%	9.00%

(1) Dominion has adopted 8.75 percent for pension benefits in 2003.
(2) The medical cost trend rate for 2002 is assumed to gradually decrease to 4.75 percent by 2007 and continues at that rate for years thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the postretirement health care plans. A one-percentage-point change in the assumed health care cost trend rate would have the following effects:

	Other Postretirement Benefits	
	One Percentage Point Increase	One Percentage Point Decrease
	(Millions)	
Effect on total service and interest cost components for 2002	$ 5	$ (4)
Effect on postretirement benefit obligation at December 31, 2002	$43	$(35)

The Company also participates in employee savings plans which cover substantially all employees. Employer matching contributions of $7 million, $9 million and $17 million were incurred in 2002, 2001 and 2000, respectively.

Certain regulatory authorities have held that amounts recovered in rates for other postretirement benefits in excess of benefits actually paid during the year must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, certain subsidiaries fund postretirement benefit costs through Voluntary Employees' Beneficiary Associations. The remaining subsidiaries do not prefund postretirement benefit costs but instead pay claims as presented.

Note 21. Commitments and Contingencies

As the result of issues generated in the ordinary course of business, the Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies, some of which involve substantial amounts of money. Management believes that the final disposition of these proceedings will not have a material adverse effect on the Company's financial position, liquidity or results of operations.

Capital Expenditures

The Company has made substantial commitments in connection with its capital expenditures program. Those expenditures are estimated to total $1.2 billion for 2003 and $1.1 billion in both 2004 and 2005. The Company expects that these expenditures will be met through a combination of sales of securities and short-term borrowings to the extent not funded by cash flows from operations.

Fuel Purchase Commitments

The Company enters into long-term purchase commitments for natural gas. Estimated payments under these commitments for the next five years and beyond are as follows: 2003—$115 million; 2004—$45 million; 2005—$21 million; 2006—$21 million; 2007—$19 million; and years beyond 2007—$215 million. These purchase commitments include those required for regulated operations. The Company generally recovers the costs of those purchases through regulated rates. The natural gas purchase commitments of the Company's field services operations are also included, net of related sales commitments. In addition, the Company has committed to purchase certain volumes of natural gas at market index prices determined in the period the natural gas is delivered. These transactions have been designated as normal purchases and sales under SFAS No. 133.

Natural Gas Pipeline and Storage Capacity Commitments

The Company enters into long-term commitments for the purchase of natural gas pipeline and storage capacity. Estimated payments under these commitments for the next five years are as follows: 2003—$34 million; 2004—$23 million; 2005—$13 million; and 2006—$1 million. There were no commitments beyond 2006.

Production Handling and Firm Transportation Commitments

In connection with gas and oil production operations, the Company has entered into certain transportation and production handling agreements with minimum commitments expected to be paid in the following years: 2003—$23 million; 2004—$57 million; 2005—$56 million; 2006—$53 million; 2007—$44 million; and years beyond 2007—$68 million.

Lease Commitments

The Company leases various facilities, vehicles and equipment under both operating and capital leases. Future minimum lease payments under the Company's operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2002 are as follows: 2003—$32 million; 2004—$34 million; 2005—$31 million; 2006—$28 million; 2007—$26 million; and years beyond 2007—$46 million. Included in the lease commitments, the Company has entered into agreement with another Dominion subsidiary, Dominion Equipment, Inc., in order to develop, construct, finance and lease a new power generation facility at the Company's Armstrong station in Pennsylvania. The project was completed in 2002 at a cost of $230 million. Upon completion, the Company began operating the new generation facility under an operating lease with future minimum lease payments as of December 31, 2002, as follows: 2003—$7 million; 2004—$13 million; 2005—$13 million; 2006—$13 million; and 2007—$13 million. The facility's operations, included in the Company's Energy segment, had no material impact on the Company's revenue, net income or cash flows for the year ended December 31, 2002.

Rental expense included in Other Operations and Maintenance Expense totaled $32 million, $34 million and $30 million for 2002, 2001 and 2000, respectively.

Environmental Matters

The Company is subject to costs resulting from a steadily increasing number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations and can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations of the Company. The Company may sometimes seek recovery of environmental-related expenditures through regulatory proceedings or through joint-interest operating agreements.

The Company has determined that it is associated with 16 former manufactured gas plant sites. Studies conducted by other utilities at their former manufactured gas plants have indicated that their sites contain coal tar and other potentially harmful materials. None of the 16 former sites, with which the Company is associated, is under investigation by any state or federal environmental agency, and no investigation or action is currently anticipated. At this time, it is not known to what degree these sites may contain environmental contamination. Therefore, the Company is not able to estimate the cost, if any, which may be required for the possible remediation of these sites.

Before being acquired by Dominion, Louis Dreyfus and two predecessor companies were one of numerous defendants in several lawsuits pending in the Texas 93rd Judicial District Court in Hildago County, Texas. The lawsuit alleges that gas wells and related pipeline facilities operated by Louis Dreyfus and facilities operated by other defendants caused an underground hydrocarbon plume in McAllen, Texas. The plaintiffs claim that they have suffered damages, including property damage and lost profits as a result of the plume. Although the results of litigation are inherently unpredictable, the Company does not expect the ultimate outcome of the case to have a material adverse impact on its financial position or results of operations.

Guarantees, Letters of Credit and Surety Bonds

As discussed in Note 4, Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others—An Interpretation of FASB Statement No. 5, 57 and 107*, requires disclosures related to the issuance of certain types of guarantees, beginning with financial statements for the year ended December 31, 2002. For purposes of consolidated financial statements, guarantees issued by a parent on behalf of its consolidated subsidiary, guarantees issued by a consolidated subsidiary on behalf of its parent or guarantees issued by a consolidated subsidiary on behalf of a sister consolidated subsidiary are not subject to the Interpretation's disclosure requirements.

Nevertheless, the Company is providing the following information about the guarantees that it and certain of its subsidiaries may issue in the ordinary course of business to provide financial or performance assurance to third parties on behalf of certain subsidiaries. These agreements include guarantees, standby letters of credit and surety bonds. The amounts subject to certain of these agreements vary depending on the covered contracts actually outstanding at any particular point in time. Guarantees and standby letters of credit are used, when necessary, to support or enhance a subsidiary's stand-alone creditworthiness. Accordingly, the Company has entered into guarantees and standby letters of credit so that third parties would be willing to enter into contracts with the subsidiaries and to extend sufficient credit to facilitate the subsidiaries' accomplishment of intended commercial purposes. In such instances, guarantees may be used to limit exposures resulting from subsidiary business activities to pre-defined amounts. While the majority of these guarantees do not have a termination date, the Company may choose at any time to limit the applicability of such guarantees to future transactions.

To the extent a liability, subject to a guarantee, has been incurred by a consolidated subsidiary, that liability is included in the Company's Consolidated Financial Statements. The Company believes it unlikely that it would be required to perform or otherwise incur any losses associated with guarantees of its subsidiaries' obligations. On behalf of consolidated subsidiaries, as of December 31, 2002, the Company had issued $1.1 billion of guarantees; purchased $40 million of surety bonds; and authorized the issuance of standby letters of credit by financial institutions of $535 million.

Indemnifications

In addition, as part of commercial contract negotiations in the normal course of business, the Company may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. The Company is unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate the Company have not yet occurred or, if any such event has occurred, the Company has not been notified of its occurrence. However, at December 31, 2002, management believes future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on its results of operations, cash flows or financial position.

Equity Contribution Commitment

CNG International, a wholly-owned subsidiary, is contractually obligated to make equity contributions of up to $100 million to an equity method investee engaged in energy-related activities in Australia in the event that the equity method investee is unable to service certain debt. See Note 8 for more information.

Note 22. Fair Value of Financial Instruments

Substantially all of the Company's financial instruments are recorded at fair value, with the exception of the instruments described below. Fair value amounts have been determined using available market information and valuation methodologies considered appropriate in the opinion of management.

The Company reports the following financial instruments based on historical cost rather than fair value. The financial instruments' carrying amounts and fair values as of December 31, 2002 and 2001 were as follows:

	2002		2001	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(Millions)			
Long-term debt(1)	$3,459	$3,636	$3,445	$3,393
Preferred securities of subsidiary trust(2)	200	205	200	200

(1) Fair value is estimated using market prices, where available; otherwise, interest rates, currently available for issuance of debt with similar terms and remaining maturities, are used. The carrying amount of debt issues with short-term maturities and variable rates repriced at current market rates is a reasonable estimate of fair value.

(2) Fair value is based on market quotations.

Note 23. Concentration of Credit Risk

Credit risk is the risk of financial loss to the Company if counterparties fail to perform their contractual obligations. The Company sells natural gas and provides distribution services to residential, commercial and industrial customers and transmission services to utilities and other energy companies. In addition, the Company enters into contracts with various companies in the energy industry for purchases and sales of energy-related commodities, including natural gas and oil, in its hedging activities. These transactions principally occur in the Northeast, Midwest and Mid-Atlantic regions of the United States. Management does not believe that this geographic concentration contributes significantly to the Company's overall exposure to credit risk. Credit risk associated with trade accounts receivable from energy consumers is limited due to the large number of customers.

Dominion and its subsidiaries, including the Company, maintain credit policies with respect to their counterparties that management believes minimize overall credit risk. Where appropriate, such policies include the evaluation of a prospective counterparty's financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. Dominion, on behalf of the Company and its subsidiaries, also monitors the financial condition of existing counterparties on an ongoing basis. The Company maintains a provision for credit losses based on factors surrounding the credit risk of its customers, historical trends and other information. Management believes, based on Dominion's credit policies and the Company's December 31, 2002 provision for credit losses, that it is unlikely that a material adverse effect on its financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

The Company calculates its gross credit exposure for each counterparty as the unrealized fair value of derivative contracts plus any outstanding receivables (net of payables, where netting agreements exist) prior to the application of collateral. At December 31, 2002, the Company held no collateral made available by its counterparties. Presented below is a summary of the Company's gross credit exposure as of December 31, 2002. The amounts presented exclude accounts receivable for gas sales and services, regulated gas transmission services and the Company's provision for credit losses.

	Gross Credit Exposure
	(Millions)
Investment grade[1]	$121
Non-investment grade[2]	20
No external ratings:	
Internal rated—investment grade[3]	5
Internal rated—non-investment grade[4]	108
Total	$254

(1) This category includes counterparties with minimum credit ratings of Baa3 assigned by Moody's Investors Service (Moody's) and BBB- assigned by Standard & Poor's Ratings Group, a division of The McGraw-Hill Companies, Inc. (Standard & Poor's). The five largest counterparty exposures, combined, for this category represented approximately 23 percent of the total gross credit exposure.

(2) This category includes counterparties with credit ratings that are below investment grade. The five largest counterparty exposures, combined, for this category represented 9 percent of the total gross credit exposure.

(3) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, but are considered investment grade based on the Company's evaluation of the counterparty's creditworthiness. The five largest counterparty exposures, combined, for this category represented approximately 2 percent of the total gross credit exposure.

(4) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, and are considered non-investment grade based on the Company's evaluation of the counterparty's creditworthiness. The five largest counterparty exposures, combined, for this category represented approximately 10 percent of the total gross credit exposure.

Note 24. Related Party Transactions

The Company exchanges certain quantities of natural gas and other commodities with other Dominion affiliates at market prices in the ordinary course of business. The affiliated commodity transactions are presented below:

	Year Ended December 31,		
	2002	2001	2000
	(Millions)		
Purchases of natural gas from affiliates	$281	$229	$25
Sales of natural gas, gas transportation and storage services to affiliates	156	135	68
Purchases of electricity from affiliates	26	4	5
Sales of electricity to affiliates	17	12	1

The Company enters into certain commodity derivative contracts with Dominion affiliates. These contracts, which are principally comprised of commodity swaps, are used by the Company to manage commodity price risks associated with the purchases and sales of natural gas. The Company designates the majority of these contracts as cash flow hedges for accounting purposes. At December 31, 2002 and December 31, 2001, the Company's Consolidated Balance Sheets included derivative assets with Dominion affiliates of $55 million and $56 million and derivative liabilities with Dominion affiliates of $48 million and $158 million, respectively. Unrealized gains or losses, representing the effective portion of the changes in fair value of these affiliate derivative contracts, are included in the balance of AOCI in the Company's Consolidated Balance Sheets. See Note 11 for further discussion of the Company's hedging activities.

The Company's income from operations includes the recognition of the following derivative gains and losses on affiliated transactions:

	Year Ended December 31,		
	2002	2001	2000
	(Millions)		
Net realized (gains) losses on commodity derivative contracts	$45	$3	$(19)

Effective February 1, 2000, Dominion created a subsidiary service company, Dominion Services, which provides certain administrative and technical services to the Company. The cost of services provided by Dominion Services to the Company during 2002, 2001 and the period January 28, 2000 through December 31, 2000 was approximately $166 million, $179 million and $30 million, respectively. In 2002 and 2001, the Company also provided services to other Dominion affiliates in the amount of $8 million and $2 million, respectively.

Effective January 1, 2001, CNG Services was merged into Dominion Services (see Note 1). Approximately $79 million of assets and $79 million of liabilities were transferred from the Company to Dominion Services.

The Company and its subsidiaries participate in a system money pool arrangement (the Money Pool) authorized by the SEC. Effective January 1, 2001, Dominion Services began administering the Money Pool, whereas prior to 2001, the Money Pool was administered by CNG Services, a subsidiary service company. After satisfaction of the borrowing needs of participants and after any possible prepayment of outstanding indebtedness, Dominion Services, as agent for the Money Pool, invests any excess Money Pool funds on a short-term basis. At December 31, 2002, there were no excess funds invested by Dominion Services on behalf of the Company. At December 31, 2001, the Company had a receivable of $60 million related to the investment of excess funds by Dominion Services.

During 2002, Dominion advanced $1.5 billion, net of repayments, to the Company pursuant to a short-term demand note (Demand Note). Dominion subsequently converted $900 million of the amounts borrowed by the Company to be an equity contribution. At December 31, 2002, the net outstanding borrowings under the Demand Note totaled $563 million. During 2002, the Company incurred $3 million in interest charges related to these borrowings.

In exchange for a reduction in amounts payable to Dominion, the Company recognized $32 million of additional paid-in capital in 2002.

The Company's accounts receivable and payable balances with affiliates are settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions.

For information about the leasing of a power generation facility in Armstrong, Pennsylvania by a subsidiary of the Company from another Dominion subsidiary, Dominion Equipment, Inc., see Note 21.

See Notes 2 and 20 for a discussion of the inclusion of the Company in Dominion's consolidated federal income tax return and the Company's participation in certain Dominion benefit plans.

Equity Method Investments

At December 31, 2002 and 2001, the Company's equity method investments totaled $202 million and $180 million, respectively. The Company's equity method investments are reported in Investments and, as discussed in Note 8, in Assets Held For Sale on the Consolidated Balance Sheets. Equity earnings on these investments totaled $23 million in 2002, $18 million in 2001 and $17 million in 2000. The equity earnings are reported in Other Income in the Consolidated Statements of Income.

Note 25. Operating Segments

The Company is organized primarily on the basis of products and services sold in the United States. The Company manages its operations based on three primary operating segments:

The ***Delivery*** segment manages the Company's retail gas distribution systems and customer service operations.

The ***Energy*** segment manages the Company's gas transmission pipeline, storage and by-product operations, certain gas production operations and the activities of the Company's gas marketing subsidiaries and the Company's nonregulated sales of electricity.

The ***Exploration & Production*** segment manages the Company's gas and oil exploration, development and production operations. Operations are located in several major producing basins in the lower 48 states, including the outer continental shelf and deep-water areas of the Gulf of Mexico.

In addition, the Company also reports the corporate functions as a segment. The ***Corporate and Other*** segment includes the activities of CNG International and other minor subsidiaries, costs of the Company's corporate functions and certain expenses which are not allocated to the operating segments, including the following:

- 2001 and 2000 restructuring and other merger-related costs of $45 million ($31 million after taxes) and $270 million ($195 million after taxes), respectively (see Note 7);
- 2001 cumulative effect of adopting SFAS No. 133 of $22 million ($14 million after taxes) (see Note 11);
- 2001 estimated impairment of natural gas contracts of $108 million ($69 million after taxes), resulting from the Company's exposure to Enron (see Note 11);
- 2000 impairment of foreign investments held for sale of $152 million ($99 million after taxes) (see Note 8);
- 2000 gain on sale of subsidiary of $163 million ($98 million after taxes) (see Note 7); and
- 2000 cumulative effect of the change in pension accounting of $42 million ($31 million after taxes) (see Note 3).

Management evaluates performance based on a measure of profit and loss that represents each segment's contribution to the Company's net income. Intersegment sales and transfers are based on underlying contractual arrangements and agreements and may result in intersegment profit or loss.

The following table presents segment information pertaining to the Company's operations:

	Year Ended December 31,					
	Delivery	Energy	Exploration & Production	Corporate and Other	Adjustments and Eliminations	Consolidated Total
				(Millions)		
2002						
Operating revenue:						
External customers	$1,245	$1,394	$1,255	$ 6	$ —	$ 3,900
Intersegment	2	85	65	—	(152)	—
Total operating revenue	1,247	1,479	1,320	6	(152)	3,900
Interest and related charges	43	22	75	209	(194)	155
Depreciation, depletion and amortization	75	69	410	—	—	554
Equity in earnings of equity method investees	—	11	5	7	—	23
Income tax expense (benefit)	68	126	133	(15)	—	312
Net income	168	205	256	9	—	638
Investment in equity method investees (at December 31)	—	73	46	83	—	202
Capital expenditures	125	184	1,339	37	—	1,685
Total assets (at December 31)	2,997	2,581	6,523	3,130	(3,010)	12,221
2001						
Operating revenue:						
External customers	1,745	1,519	942	31	—	4,237
Intersegment	2	131	67	18	(218)	—
Total operating revenue	1,747	1,650	1,009	49	(218)	4,237
Interest and related charges	57	31	45	168	(145)	156
Depreciation, depletion and amortization	76	66	265	—	—	407
Equity in earnings of equity method investees	—	12	4	2	—	18
Income tax expense (benefit)	63	105	95	(64)	—	199
Net income	148	167	202	(126)	—	391
Investment in equity method investees (at December 31)	1	63	48	68	—	180
Capital expenditures	90	351	694	21	—	1,156
Total assets (at December 31)	2,916	2,116	5,775	2,920	(2,700)	11,027
2000						
Operating revenue:						
External customers	1,981	1,097	925	12	—	4,015
Intersegment	4	153	54	138	(349)	—
Total operating revenue	1,985	1,250	979	150	(349)	4,015
Interest and related charges	58	32	45	131	(104)	162
Depreciation, depletion and amortization	84	65	286	7	—	442
Loss on net assets held for sale	—	—	—	152	—	152
Gain on sale of subsidiary	—	—	—	163	—	163
Equity in earnings of equity method investees	—	7	4	6	—	17
Income tax expense (benefit)	71	87	66	(74)	(3)	147
Net income	144	147	138	(185)	—	244
Capital expenditures	126	75	603	9	—	813

As of December 31, 2002, 2001 and 2000, and for the years ended December 31, 2002, 2001 and 2000, less than one percent of the Company's total long-lived assets and revenue were associated with international operations.

Note 26. Gas and Oil Producing Activities (Unaudited)

Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil producing activities and related aggregate amounts of accumulated depreciation, depletion and amortization follow:

	At December 31, 2002	At December 31, 2001
	(Millions)	
Capitalized costs:		
Proved properties	$7,154	$6,022
Unproved properties	1,775	1,614
	8,929	7,636
Accumulated depletion:		
Proved properties	3,141	2,844
Unproved properties	325	294
	3,466	3,138
Net capitalized costs	$5,463	$4,498

Total Costs Incurred

The following costs were incurred in gas and oil producing activities during 2000 through 2002:

	2002 United States	2001* United States	2000 Total	2000 United States	2000 Canada
			(Millions)		
Property acquisition costs:					
Proved properties	$ 243	$1,583	$215	$215	$—
Unproved properties	168	887	39	39	—
	411	2,470	254	254	—
Exploration costs	258	305	113	113	—
Development costs(1)	630	345	192	189	3
Total	$1,299	$3,120	$559	$556	$ 3

* Effective January 1, 2001, the Company transferred its 21 percent interest in heavy oil producing properties in Alberta, Canada, to another subsidiary of Dominion.

(1) Development costs incurred for proved undeveloped reserves were $205 million, $130 million and $82 million for 2002, 2001 and 2000, respectively.

Results of Operations

The Company cautions that the following standardized disclosures required by the FASB do not represent the results of operations based on its historical financial statements. In addition to requiring different determinations of revenue and costs, the disclosures exclude the impact of interest expense and corporate overhead.

	Year Ended December 31,				
	2002	2001*	2000		
	United States	United States	Total	United States	Canada
	(Millions)				
Revenue (net of royalties) from:					
Sales to nonaffiliated companies	$1,058	$706	$551	$545	$6
Transfers to other operations	98	114	98	98	—
	1,156	820	649	643	6
Less:					
Production (lifting) costs	171	103	93	90	3
Depreciation, depletion and amortization(1)	416	403	276	276	—
Income tax expense(2)	195	101	93	92	1
	782	607	462	458	4
Results of operations	$ 374	$213	$187	$185	$2

* Effective January 1, 2001, the Company transferred its 21 percent interest in heavy oil producing properties in Alberta, Canada, to another subsidiary of Dominion.

(1) Depreciation, depletion and amortization for 2001 includes a full cost impairment of $83 million, which was offset completely by the reclassification of certain deferred gains from AOCI. See Notes 11 and 12.

(2) Income tax for 2001 includes $30 million related to the full cost impairment.

Company-Owned Reserves

Estimated net quantities of proved gas and oil (including condensate) reserves in the United States at December 31, 2000 through 2002 and Canada at December 31, 2000 through 2001, and changes in the reserves during those years, are shown in the two tables which follow.

	2002	2001*			2000		
	United States	Total	United States	Canada	Total	United States	Canada
	(Billion Cubic Feet)						
Proved developed and undeveloped reserves—Gas							
Balance at January 1	2,796	1,224	1,223	1	1,205	1,204	1
Changes in reserves:							
Extensions, discoveries and other additions	634	260	260	—	142	142	—
Revisions of previous estimates	140	(76)	(76)	—	(71)	(71)	—
Production	(286)	(176)	(176)	—	(173)	(173)	—
Purchases of gas in place	379	1,573	1,573	—	129	129	—
Sales of gas in place	(1)	(9)	(8)	(1)	(8)	(8)	—
	866	1,572	1,573	(1)	19	19	—
Balance at December 31	3,662	2,796	2,796	—	1,224	1,223	1
Proved developed reserves—Gas							
Balance at January 1	2,347	974	973	1	960	959	1
Balance at December 31	2,869	2,347	2,347	—	974	973	1

* Effective January 1, 2001, the Company transferred its 21 percent interest in heavy oil producing properties in Alberta, Canada, to another subsidiary of Dominion. Proved reserves associated with the Canadian properties approximated 1 bcf of gas and 6.6 million barrels of oil at December 31, 2000. The property was transferred at market value of $4.5 million.

	2002	2001*			2000		
	United States	Total	United States	Canada	Total	United States	Canada
			(Thousands of Barrels)				
Proved developed and undeveloped reserves—Oil							
Balance at January 1	115,653	57,273	50,691	6,582	49,287	42,643	6,644
Changes in reserves:							
Extensions, discoveries and other additions	24,273	37,385	37,385	—	12,814	12,814	—
Revisions of previous estimates	4,042	(248)	(248)	—	(2,028)	(2,318)	290
Production	(8,537)	(5,989)	(5,989)	—	(7,213)	(6,861)	(352)
Purchases of oil in place	2,928	34,604	34,604	—	6,293	6,293	—
Sales of oil in place	(31)	(7,372)	(790)	(6,582)	(1,880)	(1,880)	—
	22,675	58,380	64,962	(6,582)	7,986	8,048	(62)
Balance at December 31	138,328	115,653	115,653	—	57,273	50,691	6,582
Proved developed reserves—Oil							
Balance at January 1	46,138	27,910	21,328	6,582	38,934	32,290	6,644
Balance at December 31	47,290	46,138	46,138	—	27,910	21,328	6,582

* Effective January 1, 2001, the Company transferred its 21 percent interest in heavy oil producing properties in Alberta, Canada, to another subsidiary of Dominion. Proved reserves associated with the Canadian properties approximated 1 bcf of gas and 6.6 million barrels of oil at December 31, 2000. The property was transferred at market value of $4.5 million.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

The following tabulation has been prepared in accordance with the FASB's rules for disclosure of a standardized measure of discounted future net cash flows relating to proved gas and oil reserve quantities owned by the Company.

	At December 31,				
	2002	2001*	2000		
	United States	United States	Total	United States	Canada
			(Millions)		
Future cash inflows	$21,990	$9,430	$13,506	$13,434	$72
Less: Future development costs[(1)]	958	756	396	347	49
Future production costs	2,353	2,422	756	755	1
Future income tax expense	5,999	1,727	4,072	4,068	4
	9,310	4,905	5,224	5,170	54
Future net cash flows	12,680	4,525	8,282	8,264	18
Less annual discount (10% a year)	6,514	2,197	3,146	3,140	6
Standardized measure of discounted future net cash flows[(2)]	$ 6,166	$2,328	$ 5,136	$ 5,124	$12

* Effective January 1, 2001, the Company transferred its 21 percent interest in heavy oil producing properties in Alberta, Canada, to another subsidiary of Dominion.

(1) Estimated future development costs, excluding abandonment, for proved undeveloped reserves are estimated to be $212 million, $202 million and $178 million for 2003, 2004 and 2005, respectively.

(2) Amounts exclude the effect of derivative instruments designated as hedges of future sales of production at year-end.

In the foregoing determination of future cash inflows, sales prices for gas and oil were based on contractual arrangements or market prices at year-end. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions. Future income taxes were computed by applying the appropriate year-end or future statutory tax rate to future pre-tax net cash flows, less the tax basis of the properties involved, and giving effect to tax deductions, permanent differences and tax credits.

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10 percent discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations and no value may be assigned to probable or possible reserves.

The following tabulation is a summary of changes between the total standardized measure of discounted future net cash flows at the beginning and end of each year.

	2002	2001	2000
		(Millions)	
Standardized measure of discounted future net cash flows at January 1	$ 2,328	$ 5,136	$ 1,371
Changes in the year resulting from:			
Sales and transfers of gas and oil produced during the year, less production costs	(985)	(718)	(556)
Prices and production and development costs related to future production	2,426	(6,009)	5,693
Extensions, discoveries and other additions, less production and development costs	1,685	562	1,108
Previously estimated development costs incurred during the year	205	130	81
Revisions of previous quantity estimates	(120)	(69)	(652)
Accretion of discount	326	675	194
Income taxes	(1,984)	1,452	(1,802)
Acquisition of Louis Dreyfus	—	1,347	—
Other purchases and sales of proved reserves in place, net	787	43	992
Other (principally timing of production)	1,498	(221)	(1,293)
	3,838	(2,808)	3,765
Standardized measure of discounted future net cash flows at December 31	$ 6,166	$ 2,328	$ 5,136

Note 27. Quarterly Financial Data (Unaudited)

A summary of the quarterly results of operations for the years ended December 31, 2002 and 2001 follows. Amounts shown reflect all adjustments, consisting of only normal recurring accruals, necessary in the opinion of management for a fair statement of the results for the interim periods.

Because a major portion of the gas sold or transported by the Company's distribution and transmission operations is ultimately used for space heating, both revenue and earnings are subject to seasonal fluctuations. Seasonal fluctuations may be further influenced by the timing of rate relief granted under regulation to compensate for the increased cost of providing service to customers.

	2002				2001			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
				(Millions)				
Operating revenue	$1,132	$788	$750	$1,230	$1,735	$745	$718	$1,039
Income from operations	338	186	177	369	315	143	142	133
Income before cumulative effect of a change in accounting principle	201	104	113	220	179	73	76	77
Cumulative effect of a change in accounting principle	—	—	—	—	(14)	—	—	—
Net income	201	104	113	220	165	73	76	77

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Part III

Item 10. Directors and Executive Officers of the Registrant

Omitted pursuant to General Instruction I.(2)(c).

Item 11. Executive Compensation

Omitted pursuant to General Instruction I.(2)(c).

Item 12. Security Ownership of Certain Beneficial Owners and Management

Omitted pursuant to General Instruction I.(2)(c).

Item 13. Certain Relationships and Related Transactions

Omitted pursuant to General Instruction I.(2)(c).

Item 14. Controls and Procedures

Senior management, including the Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures within 90 days of the date of this report. Based on this evaluation process, the Chief Executive Officer and Chief Financial Officer have concluded that Dominion's disclosure controls and procedures are effective. Since that evaluation process was completed, there have been no significant changes in internal controls or in other factors that could significantly affect these controls.

Part IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) Certain documents are filed as part of this Form 10-K and are incorporated by reference and found on the pages noted.

1. Financial Statements

   See Index on page 26.

2. Financial Statement Schedules

All other schedules are omitted because they are not applicable, or the required information is shown in the financial statements or the related notes.

3. Exhibits

3.1 — Certificate of Incorporation of Consolidated Natural Gas Company (Exhibit (3A)(i) to Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, incorporated by reference).

3.2 — Certificate of Amendment of Certificate of Incorporation, dated January 28, 2000 (Exhibit (3A)(ii) to Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, incorporated by reference).

3.3 — Bylaws as in effect on December 15, 2000 (Exhibit 3B to Form 10-K for the fiscal year ended December 31, 2000, File No. 1-3196, incorporated by reference).

4.1 — Indenture, dated as of May 1, 1971, between Consolidated Natural Gas Company and JP Morgan Chase Bank (formerly The Chase Manhattan Bank and Manufacturers Hanover Trust Company) (Exhibit (5) to Certificate of Notification at Commission File No. 70-5012, incorporated by reference); Fifteenth Supplemental Indenture dated as of October 1, 1989 (Exhibit (5) to Certificate of Notification at Commission File No. 70-7651, incorporated by reference); Seventeenth Supplemental Indenture dated as of August 1, 1993 (Exhibit (4) to Certificate of Notification at Commission File No. 70-8167, incorporated by reference); Eighteenth Supplemental Indenture dated as of December 1, 1993 (Exhibit (4) to Certificate of Notification at Commission File No. 70-8167, incorporated by reference); Nineteenth Supplemental Indenture dated as of January 28, 2000 (Exhibit (4A)(iii), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, incorporated by reference); Twentieth Supplemental Indenture dated as of March 19, 2001 (Exhibit 4(viii), Form 10-K for the fiscal year ended December 31, 2000, File No. 1-8489, incorporated by reference).

4.2 — Indenture, dated as of April 1, 1995, between Consolidated Natural Gas Company and The Bank of New York (as successor trustee to United States Trust Company of New York) (Exhibit (4) to Certificate of Notification at Commission File No. 70-8107); First Supplemental Indenture dated January 28, 2000 (Exhibit (4 A)(ii), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, incorporated by reference); Securities Resolution No. 1 effective as of April 12, 1995 (Exhibit 2 to Form 8-A filed April 21, 1995 under File No. 1-3196 and relating to the 7 3⁄8% Debentures Due April 1, 2005); Securities Resolution No. 2 effective as of October 16, 1996 (Exhibit 2 to Form 8-A filed October 18, 1996 under file No. 1-3196 and relating to the 6 7⁄8% Debentures Due October 15, 2026); Securities Resolution No. 3 effective as of December 10, 1996 (Exhibit 2 to Form 8-A filed December 12, 1996 under file No. 1-3196 and relating to the 6 5⁄8% Debentures Due December 1, 2008); Securities Resolution No. 4 effective as of December 9, 1997 (Exhibit 2 to Form 8-A filed December 12, 1997 under file No. 1-3196 and relating to the 6.80% Debentures Due December 15, 2027); Securities Resolution No. 5 effective as of October 20, 1998 (Exhibit 2 to Form 8-A filed October 22, 1998 under file No. 1-3196 and relating to the 6% Debentures Due October 15, 2010); Securities Resolution No. 6 effective as of September 21, 1999 (Exhibit 4A(iv), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, and relating to the 7 1⁄4% Notes Due October 1, 2004).

4.3 — Indenture, dated April 1, 2001, between Consolidated Natural Gas Company and Bank One Trust Company, National Association (Exhibit 4.1, Form S-3 File No. 333-52602, as filed on December 22, 2000, incorporated by reference); as supplemented by the Form of First Supplemental Indenture, dated April 1, 2001 (Exhibit 4.2, Form 8-K, File dated April 12, 2001, File No. 1-3196 incorporated by reference); Second Supplemental Indenture, dated October 25, 2001 (Exhibit 4.1, Form 8-K, dated October 23, 2001, File No. 1-3196, incorporated by reference); Third Supplemental Indenture, dated October 25, 2001 (Exhibit 4.3, Form 8-K, dated October 23, 2001, File No. 1-3196, incorporated by reference); Fourth Supplemental Indenture, dated May 1, 2002 (Exhibit 4.4, Form 8-K, dated May 22, 2002, Form 1-3196, incorporated by reference).

4.4 — Form of Indenture for Junior Subordinated Debentures, dated October 1, 2001, between Consolidated Natural Gas Company and Bank One Trust Company, National Association (Exhibit 4.2, Form S-3 Registration No. 333-52602, as filed on December 22, 2000, incorporated by reference); as supplemented by the First Supplemental Indenture, dated October 23, 2001 (Exhibit 4.7, Form 8-K, dated October 16, 2001, File No. 1-3196, incorporated by reference).

4.5 — Indenture, dated as of June 15, 1994, between Louis Dreyfus Natural Gas Corp., Dominion Oklahoma Texas Exploration and Production, Inc. and The Bank of New York (as successor trustee to Bank of Montreal Trust Company) (Exhibit 4.13, Form 10-K for the fiscal year ended December 31, 2001, File No. 1-8489, incorporated by reference); as supplemented by the First Supplemental Indenture, dated as of November 1, 2001 (Exhibit 4.7, Form 10-Q for the quarter ended September 30, 2001, incorporated by reference).

4.6 — Indenture, dated as of December 11, 1997, between Louis Dreyfus Natural Gas Corp., Dominion Oklahoma Texas Exploration & Production, Inc., and La Salle Bank National Association (formerly LaSalle National Bank) (Exhibit 4.14, Form 10-K for the fiscal year ended December 31, 2001, File No. 1-8489, incorporated by reference); as supplemented by the First Supplemental Indenture, dated as of November 1, 2001 (Exhibit 4.9, Form 10-Q for the quarter ended September 30, 2001, incorporated by reference).

10.1 — $1,250,000,000 364-Day Credit Agreement among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company and JPMorgan Chase Bank, as Administrative Agent for the Lenders, dated May 30, 2002 (filed herewith).

10.2 — $750,000,000 Three-Year Credit Agreement among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company and JPMorgan Chase Bank, as Administrative Agent for the Lenders, dated May 30, 2002 (filed herewith).

12 — Ratio of earnings to fixed charges (filed herewith).

23.1 — Consent of Deloitte & Touche LLP (filed herewith).

23.2 — Consent of Ralph E. Davis Associates, Inc. (filed herewith).

23.3 — Consent of Ryder Scott Company, L.P. (filed herewith).

99.1 — Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

99.2 — Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

(b) Reports on Form 8-K

There were no reports on Form 8-K filed during the fourth quarter of 2002.

Independent Auditors' Report

To Board of Directors of
Consolidated Natural Gas Company
Richmond, Virginia

We have audited the consolidated financial statements of Consolidated Natural Gas Company (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries as of December 31, 2002 and 2001, and for each of the three years in the period ended December 31, 2002, and have issued our report thereon dated January 21, 2003, which report expresses an unqualified opinion and includes an explanatory paragraph as to changes in accounting principle for: goodwill and other intangible assets in 2002, derivative instruments and hedging activities in 2001, and the method of accounting used to develop the market-related value of pension plan assets in 2000; such consolidated financial statements and report are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedules of the Company, listed in Item 15. These consolidated financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Richmond, Virginia
January 21, 2003

Consolidated Natural Gas Company (Parent Company)
Schedule I—Condensed Financial Information of Registrant
Condensed Statements of Income

	Year Ended December 31,		
	2002	2001	2000
		(Millions)	
Operating Expenses	$ (13)	$ (3)	$ 62
Income (loss) from operations	13	3	(62)
Other income:			
Affiliated interest income	191	136	144
Other	—	4	170
Total other income	191	140	314
Interest and related charges	212	168	174
Income (loss) before income taxes	(8)	(25)	78
Income tax expense (benefit)	(11)	(11)	46
Equity in undistributed earnings of subsidiaries	635	405	212
Net Income	$638	$391	$244

The accompanying notes are an integral part of the Condensed Financial Statements.

Consolidated Natural Gas Company (Parent Company)
Schedule I—Condensed Financial Information of Registrant
Condensed Balance Sheets

	At December 31, 2002	At December 31, 2001
	(Millions)	
ASSETS		
Current Assets		
Receivables and advances due from affiliates	$1,991	$1,007
Prepayments	16	53
Other	—	19
Total current assets	2,007	1,079
Investments		
Investment in affiliates	3,772	3,623
Loans to affiliates	2,299	2,398
Other	67	67
Total investments	6,138	6,088
Deferred Charges and Other Assets	30	56
Total assets	$8,175	$7,223
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Securities due within a year	$ 150	$ —
Short-term debt	397	776
Payables and short-term borrowings due to affiliates	569	57
Other	39	39
Total current liabilities	1,155	872
Long-Term Debt		
Long-term debt	3,003	3,130
Notes payable to affiliates	206	206
Total long-term debt	3,209	3,336
Deferred Credits and Other Liabilities	2	15
Total liabilities	4,366	4,223
Common Shareholder's Equity		
Common stock, no par value, 100 shares authorized and outstanding	1,816	1,816
Other paid-in capital	1,871	936
Accumulated other comprehensive income (loss)	(298)	82
Retained earnings	420	166
Total common shareholder's equity	3,809	3,000
Total liabilities and shareholder's equity	$8,175	$7,223

The accompanying notes are an integral part of the Condensed Financial Statements.

Consolidated Natural Gas Company (Parent Company)
Schedule I—Condensed Financial Information of Registrant
Condensed Statements of Cash Flows

	Year Ended December 31,		
	2002	2001	2000
	(Millions)		
Net Cash Provided By Operating Activities	$ 404	$ 294	$ 16
Investing Activities			
Money pool investments, net	(498)	84	(361)
Advances to affiliates, net of repayments	(293)	(85)	—
Loans to affiliates	(108)	(1,089)	—
Repayment of loans by affiliates	14	15	38
Investment in affiliates	(217)	(6)	(3)
Proceeds from sale of Virginia Natural Gas, net of cash transferred	—	—	532
Other	(1)	—	—
Net cash provided by (used in) investing activities	(1,103)	(1,081)	206
Financing Activities			
Issuance of long-term debt	—	1,439	—
Repayment of long-term debt	—	(84)	(45)
Short-term borrowings from parent, net	1,463	—	—
Issuance (repayment) of short-term debt, net	(379)	(435)	527
Dividends paid	(384)	(336)	(704)
Issuance of note payable to affiliate	—	206	—
Other	(1)	(3)	—
Net cash provided by (used in) financing activities	699	787	(222)
Increase (decrease) in cash and cash equivalents	—	—	—
Cash and cash equivalents at beginning of the year	—	—	—
Cash and cash equivalents at end of the year	$ —	$ —	$ —
Supplemental Cash Flow Information			
Noncash transactions from investing and financing activities:			
Conversion of amounts receivable from subsidiaries to other paid-in capital	$ 21	—	—
Conversion of short-term borrowings and other amounts payable to parent to other paid-in capital	932	—	—
Dominion's contribution of Dominion Oklahoma Texas Exploration and Production, Inc. (DOTEPI) to the Company	—	$ 894	—
Transfer of split dollar life insurance to Dominion	—	56	—

The accompanying notes are an integral part of the Condensed Financial Statements.

Consolidated Natural Gas Company (Parent Company)
Schedule I—Condensed Financial Information of Registrant
Notes to Condensed Financial Statements

Note 1. Basis of Presentation

Pursuant to rules and regulations of the Securities and Exchange Commission (SEC), the unconsolidated condensed financial statements of Consolidated Natural Gas Company (the Company) do not reflect all of the information and notes normally included with financial statements prepared in accordance with accounting principles generally accepted in the United States of America. Therefore, these financial statements should be read in conjunction with the Consolidated Financial Statements and related notes included in the 2002 Form 10-K, Part II, Item 8.

Accounting for Subsidiaries—The Company has accounted for the earnings of its subsidiaries under the equity method in the unconsolidated condensed financial statements.

Income Taxes—The unconsolidated income tax expense or benefit computed for the Company in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*, reflects the tax assets and liabilities of the Company on a stand-alone basis and the effect of filing a consolidated U.S. tax return with its subsidiaries.

Note 2. Long-Term Debt

The Company's long-term debt consists of the following:

	2002 Weighted-Average Coupon[1]	At December 31, 2002	At December 31, 2001
		(Millions)	
Senior Notes:			
5.375% to 7.375%, due 2003 to 2027	6.448%	$2,950	$2,950
6.875%, due 2026[2]	—	150	150
		3,100	3,100
Notes payable to affiliates 7.8%, due 2041	—	206	206
		3,306	3,306
Fair value hedge valuation[3]		60	38
Amount due within one year		(150)	—
Unamortized discount and premium, net		(7)	(8)
Total long-term debt		$3,209	$3,336

(1) Represents weighted-average coupon rate for debt outstanding as of December 31, 2002.

(2) At the exercised option of holders, the Company will be required on October 15, 2006 to purchase the senior notes due October 15, 2026 at 100 percent of the principal amount plus accrued interest.

(3) Represents changes in fair value of certain fixed-rate long-term debt associated with fair value hedges.

The scheduled principal payments of long-term debt at December 31, 2002 were as follows (in millions):

2003	2004	2005	2006	2007	Thereafter	Total
$150	$400	$150	$500	—	$2,106	$3,306

The Company's long-term debt agreements contain customary covenants and default provisions. As of December 31, 2002, there were no events of default under the Company's covenants.

Note 3. Guarantees, Letters of Credit and Surety Bonds

In the ordinary course of business, the Company is a party to various agreements that provide financial or performance assurance to third parties on behalf of certain subsidiaries. These agreements include guarantees, standby letters of credit and surety bonds. The amounts subject to certain of these guarantees vary depending on the covered contracts actually outstanding at any particular point in time. Guarantees and standby letters of credit are used, when necessary, to support or enhance a subsidiary's stand-alone creditworthiness. Accordingly, the Company has entered into guarantees and standby letters of credit so that third parties would be willing to enter into contracts with the subsidiaries and to extend sufficient credit to facilitate the subsidiaries' accomplishment of intended commercial purposes. In such instances, guarantees may be used to limit exposures resulting from subsidiary business activities to pre-defined amounts. While the majority of these guarantees do not have a termination date, the Company may choose at any time to limit the applicability of such guarantees to future transactions.

Guarantees

As of December 31, 2002, the outstanding guarantees of $1.1 billion represented the following types of guarantees:

Guarantee of Subsidiary Debt—The Company has guaranteed the payment of interest and principal on Dominion Oklahoma Texas Exploration and Production Inc.'s (DOTEPI) debt of $288 million. In the event of default by DOTEPI, the Company would be obligated to repay such amounts.

Guarantees Supporting Commodity Transactions of Subsidiaries—The Company has also guaranteed contract payments up to approximately $821 million, primarily for certain of its subsidiaries involved in natural gas and oil production, natural gas delivery and energy marketing activities. These guarantees were provided to counterparties in order to facilitate physical and financial transactions in gas, pipeline capacity, transportation, oil, electricity and related commodities and services. If any one of these subsidiaries fails to perform or pay under the contracts and the counterparties seek performance or payment, the Company would be obligated to satisfy such obligation. The Company receives similar guarantees from counterparties as collateral for credit extended by the Company.

Other—The Company has also guaranteed amounts up to $35 million if certain environmental events should occur in the future related to gas and oil producing activities conducted by some of the Company's subsidiaries.

Standby Letters of Credit

At December 31, 2002, the Company had authorized the issuance of standby letters of credit by financial institutions totaling $535 million, for the benefit of counterparties that had extended credit to the Company. In the unlikely event that the Company does not pay amounts when due under the covered contracts, the counterparties may present their claims for payment to the financial institutions, which would then request payments from the Company. The $500 million of letters of credit were provided under the 364-day revolving credit facility that matures in August 2003. The remaining $35 million of the Company's letter of credit was backed by the 3-year revolving credit facility that matures in May 2005. As of December 31, 2002, no amounts had been presented for payment under these letters of credit.

Surety Bonds

At December 31, 2002, the Company had issued $40 million of surety bonds primarily in connection with licenses, permits, leases and well drilling. Under the terms of the surety bonds, the Company and then Dominion Resources, Inc. are obligated to indemnify the respective surety bond company for any amounts paid on behalf of the Company's subsidiaries.

Indemnifications

In addition, as part of commercial contract negotiations in the normal course of business, the Company may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. The Company is unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate the Company have not yet occurred or, if any such event has occurred, the Company has not been notified of its occurrence. However, at December 31, 2002, management believes future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on its results of operations, cash flows or financial position.

Note 4. Dividend Restrictions

The Company received dividends from its consolidated subsidiaries in the amounts of $345 million, $336 million and $188 million for 2002, 2001 and 2000, respectively.

The Public Utility Holding Company Act of 1935 (1935 Act) and related regulations issued by the SEC impose restrictions on the transfer and receipt of funds by a registered holding company from its subsidiaries, including a general prohibition against loans or advances being made by the subsidiaries to benefit the registered holding company. Under the 1935 Act, registered holding companies and their subsidiaries may pay dividends only from retained earnings, unless the SEC specifically authorizes payments from other capital accounts. At December 31, 2002, the Company's consolidated subsidiaries had approximately $2.7 billion in capital accounts other than retained earnings, representing capital stock, additional paid-in capital and accumulated other comprehensive income. The Company had approximately $3.4 billion in capital accounts other than retained earnings at December 31, 2002. In 2000, in response to a Dominion request, the SEC granted relief, authorizing payment of dividends by the Company from other capital accounts to Dominion in amounts up to $1.6 billion, representing the Company's retained earnings prior to Dominion's acquisition of the Company. The Company submitted a similar request to the SEC in 2002, seeking relief from this restriction in regard to DOTEPI, the subsidiary into which Louis Dreyfus was merged. The application requests relief up to approximately $303 million, representing Louis Dreyfus' retained earnings prior to the acquisition by Dominion.

Consolidated Natural Gas Company
Schedule II—Valuation and Qualifying Accounts

Column A		Column B	Column C		Column D	Column E
			Additions			
Description		Balance at Beginning of Period	Charged to Expense	Charged to Other Accounts	Deductions	Balance at End of Period
				(Millions)		
Valuation and qualifying accounts which are deducted in the balance sheet from the assets to which they apply:						
Allowance for doubtful accounts—Customers	2000	$ 21	$ 55	$ (1)	$ 24[(a)]	$ 51
	2001	51	35	—	34[(a)]	52
	2002	52	33	—	35[(a)]	50
Reserves:						
Discontinued operations	2000	2	(2)	—	—	—
	2001	—	—	—	—	—
	2002	—	—	—	—	—
Liability for workforce reductions	2000	9	—	—	6[(b)]	3
	2001	3	—	—	3[(b)]	—
	2002	—	—	—	—	—
Liabilities for restructuring and other merger-related costs:						
1999 Plan						
Severance and related costs	2000	1	—	—	1[(b)]	—
	2001	—	—	—	—	—
	2002	—	—	—	—	—
2000 Plan						
Severance and related costs—Involuntary	2000	—	31	—	18[(b)]	13
	2001	13	(2)[(c)]	(2)[(d)]	8[(b)]	1
	2002	1	—	—	1[(b)]	—
Severance and related costs—Voluntary	2000	—	2	—	—[(b)]	2
	2001	2	—	—	2[(b)]	—
	2002	—	—	—	—	—
Lease termination and restructuring	2000	—	11	—	5[(b)]	6
	2001	6	—	—	5[(b)]	1
	2002	1	—	—	1[(b)]	—
Other	2000	—	6	—	3[(b)]	3
	2001	3	—	—	2[(b)]	1
	2002	1	—	—	1[(b)]	—
2001 Plan						
Severance and related costs	2001	—	13	—	—	13
	2002	13	(4)[(c)]	—	5[(b)]	4
Lease termination and restructuring	2001	—	9	—	2[(b)]	7
	2002	7	—	—	1[(b)]	6

(a) Represents net amounts charged-off as uncollectible.
(b) Represents payments of liabilities.
(c) Represents adjustments reflecting changes in estimates.
(d) Represents transfer due to merger of the Company's service company into Dominion's service company.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONSOLIDATED NATURAL GAS COMPANY

By: /s/ THOS. E. CAPPS

(Thos. E. Capps, Chairman of the Board of Directors, President and Chief Executive Officer)

Date: March 20, 2003

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 20th day of March, 2003.

Signature	Title
/s/ THOS. E. CAPPS **Thos. E. Capps**	Chairman of the Board of Directors, President and Chief Executive Officer
/s/ THOMAS N. CHEWNING **Thomas N. Chewning**	Executive Vice President, Chief Financial Officer and Director
/s/ THOMAS F. FARRELL, II **Thomas F. Farrell, II**	Executive Vice President and Director
/s/ DUANE C. RADTKE **Duane C. Radtke**	Executive Vice President and Director
/s/ STEVEN A. ROGERS **Steven A. Rogers**	Vice President and Controller (Principal Accounting Officer)

Certifications

I, Thos. E. Capps, certify that:

1. I have reviewed this annual report on Form 10-K of Consolidated Natural Gas Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 20, 2003

/s/ THOS. E. CAPPS

Thos. E. Capps
President and Chief Executive Officer

I, Thomas N. Chewning, certify that:

1. I have reviewed this annual report on Form 10-K of Consolidated Natural Gas Company

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 20, 2003

/s/ THOMAS N. CHEWNING

Thomas N. Chewning
Executive Vice President and Chief Financial Officer